Energy Transfer Partners, L.P.
Form 10-K
October 30, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended August 31, 2007

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.)**

3738 Oak Lawn Avenue, Dallas, Texas 75219

(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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer.

See definition of accelerated filer in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer x Accelerated filer ¨ Non accelerated filer ¨

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, 2007, 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 $4,004,074,991. 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 October 16, 2007, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	137,067,059 Common Units

Documents Incorporated by Reference: None

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2007 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 relate 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 expressio 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 1A of this annual report.

Definitions

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
Capacity	Capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels.
Dekatherm	Million British thermal units. A therm factor is used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used.
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.
Wobbe	A number representing the interchange ability of fuel gases an indicator of the similarity between a specific natural gas and propane-air mixture.

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ITEM 1. BUSINESS

Overview

We (Energy Transfer Partners, L.P., a Delaware limited partnership, ETP or the Partnership) are one of the three largest publicly traded master limited partnerships in the United States in terms of equity market capitalization (approximately $7.4 billion as of October 15, 2007). The activities in which we are engaged, all of which are in the United States, and the wholly-owned subsidiary operating partnerships (collectively referred to as the Operating Partnerships) through which we conduct those activities are as follows:

- Natural gas operations, consisting of the following segments:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP),
  - interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, LLC (ETC MEP);
- Retail propane through Heritage Operating, L.P (HOLP) and Titan Energy Partners, L.P. (Titan).

Unless the context requires otherwise, the Partnership, the Operating Partnerships, and their subsidiaries are collectively referred to in this report as we , us , ETP , Energy Transfer or the Partnership.

Significant Fiscal Year 2007 Achievements

Our significant fiscal year 2007 achievements included the following, as discussed in more detail herein:

- Revenues of approximately $7.0 billion, operating income of approximately $830.0 million and net income of approximately $676.0 million. See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.
- The acquisition of the Transwestern pipeline on December 1, 2006. See Note 2 to our consolidated financial statements.
- The execution of an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of the Midcontinent Express pipeline (MEP). See Note 3 to our consolidated financial statements.
- Completion of the Cleburne to Carthage pipeline.
- Began construction of the Southeast Bossier pipeline, approximately 157 miles of predominately 42-inch pipe connecting our East Texas and Cleburne to Carthage pipelines with the Texoma pipeline (which is a part of our HPL System) north of Beaumont, Texas, which we expect to complete by the second calendar quarter of 2008.

Began construction of the Paris Loop pipeline, a 135 mile pipeline connecting our existing pipelines in the Barnett Shale region to our Texoma pipeline in Lamar County, Texas, which we expect to complete in the second calendar quarter of 2008.

Initiation of the Phoenix project, a planned expansion of the Transwestern pipeline.

Completion of the first phase of the natural gas processing plant in Godley, Texas.

Other Developments

On May 7, 2007, Ray Davis, previously the Co-Chairman and Co-Chief Executive Officer of ETP (see below), and Natural Gas Partners VI, L.P. (NGP) and affiliates of each, sold approximately 38.9 million Common Units of ETE (17.6% of the outstanding Common Units of ETE) to Enterprise GP Holdings, L.P. (Enterprise or EPE). In addition to the purchase of ETE Common Units, Enterprise also acquired a 34.9% non-controlling equity interest in the General Partner of ETE, LE GP, L.L.C. (LE GP). As a result of these transactions, EPE and its subsidiaries are considered related parties (see Note 12 of our consolidated financial statements).

Ray C. Davis, previously the Co-Chief Executive Officer and Co-Chairman of ETP, and Co-Chairman of ETE, retired from these positions effective as of August 15, 2007. As a result of Mr. Davis retirement, Kelcy L. Warren, formerly

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Co-Chief Executive Officer and Co-Chairman of ETP and Co-Chairman of ETE, became the sole Chief Executive Officer and Chairman of ETP and sole Chairman of ETE upon the effective date of Mr. Davis retirement. Mr. Davis will continue to serve as a director of ETP and ETE.

Segment Overview and Business Description

Our segments and business are as described below. See Notes 1 and 14 to our consolidated financial statements for additional segment information and the financial information of our segments for our fiscal years ended August 31, 2007, 2006 and 2005.

Natural Gas Operations

The following map depicts the major components of our natural gas operations:

Midstream

Southeast Texas System

- 4,300 miles of natural gas pipeline
- 1 natural gas processing plant (the LaGrange plant) with aggregate capacity of 240 MMcf/d
- 5 natural gas treating facilities with aggregate capacity of 720 MMcf/d
- 3 natural gas conditioning facilities with aggregate capacity of 450 MMcf/d

North Texas System

- 160 miles of natural gas pipeline
- 1 natural gas processing plant (the Godley plant) with current capacity of approximately 300 MMcf/d and construction in progress to increase the aggregate processing capacity to approximately 500 MMcf/d
- 1 natural gas conditioning facility with capacity of 100 MMcf/d

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Canyon Gathering System (acquired October 2007)

- 1,800 miles of natural gas pipeline
- 6 natural gas conditioning facilities with aggregate capacity of 90 MMcf/d

Intrastate Transportation Pipelines and Storage Facilities

ET Fuel System

- Capacity of 3.1 Bcf/d
- 2,200 miles of natural gas pipeline
- 2 storage facilities with 12.4 Bcf of total working capacity

Oasis pipeline

- Capacity of 1.2 Bcf/d
- 583 miles of natural gas pipeline
- Connects Waha to Katy market hubs

Houston pipeline system (HPL System)

- Capacity of 4.4 Bcf/d
- 4,400 miles of natural gas pipeline
- 6 natural gas treating facilities with aggregate capacity of 280 MMcf/d
- Bammel storage facility with 62 Bcf of total working capacity

East Texas pipeline

Capacity of 740 MMcf/d

168 miles of natural gas pipeline

Interstate Transportation Pipelines

Transwestern pipeline (acquired December 2006)

Capacity of 2.1 Bcf/d

2,400 miles of interstate natural gas pipeline

Midcontinent Express pipeline

Initial planned capacity of 1.4 Bcf/d

500 miles of interstate natural gas pipeline

50/50 joint venture with Kinder Morgan

Our Midstream Operations

Our midstream business owns and operates approximately 6,260 miles of in service natural gas gathering pipelines, three natural gas processing plants, five natural gas treating facilities, and ten natural gas conditioning facilities. Our midstream segment focuses on the gathering, compression, treating, blending, 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, the Bossier Sands in east Texas, and the Uinta and Piceance Basins in Utah and Colorado.

The midstream segment accounted for approximately 15% of our total consolidated operating income for the year ended August 31, 2007. Our midstream segment results are derived primarily from margins we realize for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems, processed at our processing and treating facilities, and the volumes of NGLs processed at our facilities. We also market natural gas on our pipeline systems in addition to other pipeline systems to realize incremental revenue on gas purchased, increase pipeline utilization and provide other services that are valued by our customers. In addition we generate income from limited trading activities, principally from the use of derivatives, in accordance with our commodity risk management policy. See Item 7A, Quantitative and Qualitative Disclosures About Market Risk .

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Our midstream segment consists of the following:

- The Southeast Texas System, a 4,300-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, five treating facilities and three conditioning facilities. This system is connected to the Katy Hub through the 168-mile East Texas pipeline and is also connected to the Oasis pipeline, as well as two power plants.

The La Grange processing plant is a cryogenic natural gas processing plant that processes the rich natural gas that flows through our system to produce residue gas and NGLs. The plant has a processing capacity of approximately 240 MMcf/d. Our five treating facilities have an aggregate capacity of 700 MMcf/d. These treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications. Our three conditioning facilities have an aggregate capacity of 450 MMcf/d. These conditioning facilities remove heavy hydrocarbons from the gas gathered into our systems so the gas can be redelivered and meet downstream pipeline hydrocarbon dew point specifications.

- The North Texas System, a 160-mile integrated system located in four counties in North Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett Shale trend. The system includes our Godley plant, as discussed below.

The Godley plant was built in two phases to process rich natural gas produced from the Barnett Shale and is connected with the North Texas System and the ET Fuel System. The facility consists of a cryogenic processing plant with processing capacity of approximately 300 MMcf/d. Construction is in progress to increase the aggregate processing capacity to approximately 500 MMcf/d. Construction is scheduled to be completed in the third calendar quarter of 2008.

- The Canyon Gathering System consists of approximately 1,800 miles of gathering pipeline ranging in diameters from two inches to 16 inches in the Piceance-Uinta Basin of Colorado and Utah and six conditioning plants with an aggregated processing capacity of 90 MMcf/d. The system currently gathers approximately 130,000 MMBtu/d from 1,400 wells and is connected to five major pipeline systems.

- Interests in various midstream assets located in Texas and Louisiana, including the Vantex System, the Rusk County Gathering System, the Whiskey Bay System, and the Chalkley Transmission System. On a combined basis, these assets have a capacity of approximately 550 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 attract 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 intrastate 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 insight and market intelligence, which may impact our expansion and acquisition strategy.

Our Intrastate Transportation and Storage Operations

Our intrastate transportation and storage business owns and operates approximately 7,500 miles of natural gas transportation pipelines, three natural gas storage facilities and six natural gas treating facilities.

Through ETC OLP, we own the largest intrastate pipeline system in the United States with interconnects to major consumption areas throughout the United States. Our intrastate 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 natural gas pipeline and storage assets that are referred to as the ET Fuel System, and our HPL System, which are described below.

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Our intrastate transportation and storage operations accounted for approximately 59% of our total consolidated operating income for the year ended August 31, 2007. The results from our intrastate transportation and storage segment are primarily derived from the fees we charge to transport natural gas on our pipelines, including a fuel retention component. We also generate 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, we purchase natural gas from either the market (including purchases from our midstream segment s producer services) or 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 based on an index price.

We also utilize our Bammel storage facility to engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We generally 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.

Our intrastate transportation and storage segment consists of the following:

The ET Fuel System, which serves some of the most active drilling areas in the United States, is comprised of approximately 2,200 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 near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in east Texas, the three major natural gas trading centers in Texas. The ET Fuel System has total system throughput capacity of approximately 3.3 Bcf/d of natural gas and total working storage capacity of 12.4 Bcf of natural gas.

The ET Fuel System also 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. Included in the ET Fuel System is a significant portion of our recently completed Cleburne to Carthage pipeline that connects our North Texas pipeline (NTP), a part of our ET Fuel System, our pipelines in the Barnett Shale region, and our Bethel storage facility to our Texoma pipeline in East Texas.

In addition, the ET Fuel System is connected with our Godley plant. This gives us the ability to bypass the plant when processing margins are unfavorable by blending the un-treated natural gas from the North Texas System with natural gas on the ET Fuel System while continuing to meet pipeline quality specifications.

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 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 access for natural gas on the Southeast Texas System 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 HPL System is comprised of approximately 4,400 miles of intrastate natural gas pipeline with an aggregate capacity of 4.4 Bcf/d, six treating facilities with aggregate capacity of 280 MMcf/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 of Texas, 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 HPL System also includes 32 miles of the Cleburne to Carthage pipeline from our Texoma pipeline interconnect to the Carthage Hub. The HPL System is well situated to gather gas in many of the major gas producing areas in

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Texas and has a particularly strong presence in the key Houston Ship Channel and Katy Hub markets, which significantly contributes to our overall ability to play an important role in the Texas natural gas markets. The HPL 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 our operation of the Bammel storage facility.

The Bammel storage facility has a total working gas capacity of approximately 62 Bcf and has a peak withdrawal rate of 1.3 Bcf/d. The field 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. 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.

On October 9, 2007, we announced our plan to expand our Cleburne to Carthage pipeline from the Texoma pipeline interconnect to the Carthage Hub (the Carthage Loop), adding an additional 500 MMcf/d of capacity to the Carthage Hub. The Carthage Loop is expected to be in service by the third calendar quarter of 2008.

The East Texas pipeline is a 168-mile natural gas pipeline that connects three treating facilities, one of which we own, with our Southeast Texas System. This pipeline was the first phase of a multi-phased project that increased service to producers in East and North Central Texas and provided 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 County Compressor Station. Over 500 MMcf/d of pipeline capacity is contracted under long-term agreements.

On October 9, 2007, we announced an expansion (the Katy expansion) of our East Texas pipeline with the installation of 56 miles of 36-inch pipeline and the addition of 20,000 horsepower of compression. The Katy expansion will increase the capacity on the East Texas pipeline from approximately 700 MMcf/d to more than 1.1 Bcf/d and is expected to be in service by the third calendar quarter of 2008.

Interstate Transportation Operations

Our interstate transportation segment accounted for approximately 12% of our total consolidated operating income for the year ended August 31, 2007. The results from our interstate transportation segment are primarily derived from the fees earned from natural gas transportation services and operational gas sales. Our interstate transportation operation began in fiscal 2007 with the acquisition of the Transwestern pipeline.

Our interstate transportation segment consists of the following:

The Transwestern pipeline, an open-access natural gas interstate pipeline extending approximately 2,400 miles from the gas producing regions of West Texas, eastern and northwest New Mexico, and southern Colorado primarily to pipeline interconnects off the east end of its system and to pipeline interconnects at the California border. The Transwestern pipeline has access to three significant gas basins: the Permian Basin in West Texas and eastern New Mexico; the San Juan Basin in northwest New Mexico and southern Colorado; and the Anadarko Basin in the Texas and Oklahoma panhandle. Natural gas sources from the San Juan Basin and surrounding producing areas can be delivered eastward to Texas intrastate and mid-continent connecting pipelines and natural gas market hubs as well as westward to markets like Arizona, Nevada and California. Transwestern s customers include local distribution companies, producers, marketers, electric power generators and industrial end-users. Transwestern transports natural gas in interstate commerce. As a result, Transwestern qualifies as a natural gas company under the Natural Gas Act and is subject to the regulatory jurisdiction of FERC, which regulates our interstate natural gas pipeline interests (see The Midstream and Transportation and Storage Segments Regulation). The operating results for Transwestern are included in our results on a consolidated basis as of the acquisition date (December 1, 2006).

During fiscal year 2007, we initiated the Phoenix project, consisting of 260 miles of 42-inch and 36-inch pipeline lateral, with a throughput capacity of 500 MMcf/d, connecting the Phoenix area to Transwestern s existing mainline at Ash Fork, Arizona and approximately 25 miles of 36-inch pipeline looping of Transwestern s existing San Juan lateral, adding 375 MMcf/d of capacity. Transwestern filed with the Federal Energy Regulatory Commission (FERC) for a certificate of public convenience and necessity on September 15, 2006 in Docket No. CP06-459. The final Environmental Impact Statement was issued by FERC on September 21, 2007. A final FERC certificate is expected in fall 2007, with construction beginning immediately thereafter. The project is expected to be partially in-service in the third calendar quarter of 2008 and completely in-service in the fourth calendar quarter of 2008.

A joint development with Kinder Morgan Energy Partners, L.P. for our 50% interest in MEP, an approximately 500-mile interstate natural gas pipeline scheduled to be in service during the second calendar quarter of 2009, that will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco s interstate natural gas pipeline in Butler, Alabama, that transports natural gas to the significant natural gas markets in the northeast portion of the United States. As of and for the year ended, August 31, 2007, the activity related to MEP was not material to our consolidated results of operations, financial position or cash flows.

Retail Propane Operations

Through HOLP and Titan, we are one of the three largest retail propane marketers in the United States, based on gallons sold. We serve more than one million customers from approximately 440 customer service locations in approximately 40 states. Our propane operations extend from coast to coast with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States. Our propane business has grown primarily through acquisitions of retail propane operations and, to a lesser extent, through internal growth.

Our retail propane operations accounted for approximately 15% of our total consolidated operating income for the year ended August 31, 2007. The retail propane segment is a margin-based business 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. 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.

Our propane business is largely seasonal and dependent upon weather conditions in our service areas. Historically, approximately two-thirds of our retail propane volume and substantially all of our propane-related operating income, 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 segment 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. Cash flow from operations is generally greatest during our second and third fiscal quarters when customers pay for propane purchased during the six-month peak-heating season. Sales to commercial and industrial 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 in our areas of operations, particularly during the six-month peak-heating season, to have a significant effect on the financial performance of 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.

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. 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.

Business Strategy and Competitive Strengths

Our business strategy 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 natural gas operations and retail propane business, we will be best positioned to achieve our objectives.

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We expect that acquisitions in natural gas operations will be the primary focus of our acquisition strategy going forward as evidenced by our acquisition of the Transwestern pipeline and Canyon Gathering System, although we will also continue to pursue complementary propane acquisitions as evidenced by our acquisition of Titan in June 2006. We also anticipate that our natural gas operations will provide internal growth projects of greater scale compared to those available in our propane business as demonstrated by our Cleburne to Carthage pipeline, the Phoenix project and other recently announced projects.

We believe that we are well-positioned to compete in both the natural gas operations and retail 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 credit facility and our 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 that 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.

Natural Gas Operations 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 under long-term producer commitments, 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 and transportation services. These projects include those discussed above and include the construction of the Cleburne to Carthage pipeline, the Phoenix project, the expansion of the processing capacity at our Godley plant, and our Southeast Bossier pipeline connecting the Barnett Shale to our Texoma pipeline. We expect that these expansions will lead to additional growth opportunities in this area.

Increase cash flow from fee-based businesses. Excluding results from our marketing activities, the portion of our gross margin in our natural gas operations 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 our exposure to changes in the prices of natural gas and NGLs.

Growth through acquisitions. We intend to continue 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. As demonstrated by our acquisitions of the Transwestern pipeline and the Canyon Gathering System, 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, with growing demand for natural gas or that otherwise provide the opportunity to provide our customers with increased flexibility to transport natural gas from additional supply basins and additional markets.

Natural Gas Operations Business Strengths

Our assets provide marketing flexibility through our access to numerous markets and customers. The combination of our Oasis pipeline and our 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

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System in June 2004, the HPL System acquisition in January 2005, and the completion of the East Texas pipeline, we have also increased our access to additional power plants, industrial users, municipalities, and co-operatives, and the added storage facilities add flexibility for fuel management services. The completion of the Cleburne to Carthage pipeline and other related projects provides producers with firm capacity out of the Barnett Shale and other major producing areas to all major market hubs in Texas and numerous interstate pipelines. We also provide producers with additional firm access to west coast markets with the acquisition of the Transwestern pipeline.

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 such as the Barnett Shale. We expect the acquisition of the Transwestern pipeline will provide us with market presence in other prolific gas-producing regions in the western United States. We also expect the acquisition of the Canyon Gathering System will provide us with market presence in the Piceance-Uinta Basins in Colorado and Utah.

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 and Godley processing plants reduces our commodity price risk. A significant benefit of our ownership of the Oasis pipeline and ET Fuel System is that we can elect not to process natural gas at our processing plants 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 or North Texas System with lean gas, or gas with a low NGL content, transported on the Oasis pipeline or ET Fuel System. 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.

The HPL 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 HPL System, has a total working gas capacity of approximately 62 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 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 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 one of the three largest propane marketers in the United States 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 could 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.

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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 business continuity which minimizes customer loss. We believe that this strategy has also helped to make us an attractive buyer for many propane acquisition candidates from a 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.

Natural Gas Operations Segments

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 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, in its 2007 annual outlook, total domestic consumption of natural gas is expected to increase from an estimated 22.0 Tcf consumed in 2005 to 26.1 Tcf in 2030. During the five-year period ended December 31, 2006, the United States has on average consumed approximately 22.3 Tcf per year, with average domestic production of approximately 23.8 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

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which it is produced. Natural gas from certain formations is higher 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.

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 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 varying 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 could be significant to our overall profitability.

During the year ended August 31, 2007, none of our customers individually accounted for more than 10% of our midstream, intrastate transportation and storage and interstate segment revenues.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. Under the Natural Gas Act (NGA), FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, transportation service includes storage service. The Transwestern pipeline transports natural gas in interstate commerce and thus qualifies as a natural gas company under the Natural Gas Act and is subject to the regulatory jurisdiction of FERC. 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:

- rate structures;
- rates of return on equity;

recovery of costs;

the services that our regulated assets are permitted to perform;

the acquisition, construction and disposition of assets; and

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to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, 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. Natural gas companies may not charge rates that have not been determined to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

On September 29, 2006, Transwestern filed revised tariff sheets under section 4(e) of the Natural Gas Act (NGA) proposing a general rate increase to be effective on November 1, 2006. On March 9, 2007, Transwestern filed with the FERC its Stipulation and Agreement of Settlement (Stipulation and Agreement) which provides for (i) revised base tariff rates, (ii) the amortization of certain costs, including the Enron Cash Balance Plan, regulatory commission expense, post retirement benefits, the accumulated reserve adjustment regulatory asset, deferred income taxes, and certain non-PCB environmental costs, and (iii) a depreciation rate of 1.20 percent for all transmission plant facilities. On April 27, 2007, the FERC approved the Stipulation and Agreement with an effective date of April 1, 2007. Transwestern s tariff rates and fuel charges are now final until October 2011, the time stipulated in the settlement for the commencement of a new rate case.

The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities. Any successful complaint or protest against Transwestern s FERC-approved rates could have a prospective impact on our revenues associated with providing transmission services on Transwestern s pipelines.

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

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline gathering and operations generally are not subject to rate regulation by FERC under the NGA; however, FERC s regulation influences certain aspects of our business and the market for our products. 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. The rates, terms and conditions of some transportation and storage services provided on the Oasis pipeline, HPL System, East Texas pipeline and ET Fuel System are subject to FERC regulation pursuant to Section 311 of the NGPA. 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. Should FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. 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 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.

In addition, our intrastate natural gas pipeline operations in Texas are subject to regulation by various agencies in Texas, principally the Texas Railroad Commission (TRRC), where they are located. Our intrastate pipeline and storage operations in Texas are also 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.

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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 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 we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

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 could be 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, Louisiana 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 the right of 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 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 allegations. Our gathering operations could be adversely affected should they be subject in the future to the application

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of additional or different 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.

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 NGPSA 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.

Retail Propane Segment

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.

Competition

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. According to industry publications, propane accounts for 6 $^{1}/2$ % 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 in their area of operations. 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.

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Products, Services and Marketing

We distribute propane through a nationwide retail distribution network consisting of approximately 440 customer service locations in approximately 40 states, concentrated in large part in the western, upper midwestern, northeastern and southeastern regions of the United States.

Typically, customer service locations are found in suburban and rural areas where natural gas is not readily available. Such locations generally 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, which generally holds 2,500 to 3,000 gallons of propane, is loaded with propane from the storage tank. Propane is then delivered to the customer by the bobtail truck 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.

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.

Of the retail gallons we sold, approximately 57% were to residential customers, 30% were to industrial, commercial and agricultural customers, and 13% were to other retail users. Sales to residential customers in the fiscal year ended August 31, 2007 accounted for 57% of total retail 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 23% of our gross profit from propane sales for the fiscal year ended August 31, 2007, with all other retail users accounting for 8%. No single customer accounts for 10% or more of consolidated revenues.

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

Our supplies of propane historically have been readily available from our supply sources. 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, 2007, Targa Liquids (Targa) and Enterprise Products Operating L.P. (Enterprise) provided approximately 23.0% and 22.0% of our combined total propane supply, respectively. Enterprise is a subsidiary of Enterprise GP Holdings, L.P. (Enterprise GP), an entity that owns approximately 17.6% of the outstanding ETE Common Units and a 34.9% non-controlling equity interest in LE GP and is therefore considered to be an affiliate of us. Titan purchases substantially all of its propane from Enterprise pursuant to an agreement that expires in 2010. Additionally, HOLP has a monthly storage contract with TEPPCO Partners, L.P. (an affiliate of Enterprise).

In addition, M-P Energy Partnership (M-P Energy), a Canadian partnership in which our wholly-owned subsidiary, M.P. Oils, Ltd. (MP Oils), owned through August 31, 2007 a 60% interest, procured 20.7% of our combined total propane supply during the fiscal year ended August 31, 2007. M-P Energy buys and sells propane for its own account and supplies propane to us for our northern United States operations. We sold our interest in MP Oils in October 2007. We have executed a seven-year propane purchase agreement in connection with the sale of MP Oils (see Note 8 to our consolidated financial statements).

We believe that if supplies from Targa or Enterprise were interrupted we would be able to secure adequate propane supplies from other sources without a material disruption of our operations. Aside from Targa, Enterprise, and the supply procured by M-P Energy, no single supplier provided more than 10% of our total domestic propane supply during the fiscal year ended August 31, 2007. Although we cannot assure you that supplies of propane will be readily available in the future, 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. 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.

Except for Titan s supply agreement and the new agreement with MP Oils, 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 at 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. We generally have attempted to reduce price risk by purchasing propane on a short-term basis. We have on occasion purchased for future resale significant volumes of propane for storage 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. We receive our supply of propane predominately through railroad tank cars and common carrier transport.

We lease space in larger storage facilities in Michigan, Arizona, New Mexico and Texas, 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.

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.

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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 if such upsets, releases, or spills were to occur. 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 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, 2007 an accrual of $13.5 million was recorded in our consolidated balance sheet to cover estimated environmental liabilities including certain matters assumed in connection with our acquisition of the HPL System. We have also recorded a receivable of $0.4 million to account for the predecessor owner s share of certain environmental liabilities of ETC OLP. In addition, we recorded an accrual of $3.0 million in connection with our acquisition of Titan for the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for presence of polychlorinated biphenyls (PCBs) which are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue for several years is approximately $12.3 million. Transwestern received FERC approval for rate recovery of the portion of soil and groundwater remediation not related to PCBs effective April 1, 2007.

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Transwestern continues to incur certain costs related to PCBs that could migrate into customers facilities. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing the PCBs. Costs of these remedial activities totaled approximately $0.4 million for the period since acquisition. Future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at August 31, 2007. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

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. Environmental regulations were recently modified for United States Environmental Protection Agency s Spill Prevention, Control and Countermeasures (SPCC) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

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. We currently comply with the terms of this permit and associated regulations requiring specified reductions in nitrogen oxides or NOx emissions. During 2006 and 2007 we spent an estimated $3.0 million to modify the compressor engines at the facility. In addition, we have established 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. The NOx baseline has been established and we have 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. 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 pipeline operations are subject to regulation by the U.S. Department of Transportation (DOT) under the Pipeline Hazardous Materials Safety Administration (PHMSA), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas . 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. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements for our existing transportation assets other than Transwestern pipeline will result in capital costs of $7.9 million during the period between the remainder of calendar year 2007 through 2008, as well as operating and maintenance costs of $13.1 million during that period. During this same time period, we estimate that we will incur pipeline integrity operating and on-going annual maintenance capital costs of $18.7 million with respect to our Transwestern pipeline. Through August 31, 2007, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2010. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

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 hazardous

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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 7, 2007, we employed 976 people to operate our natural gas operation segments. We employ 4,340 full-time employees to operate our propane segments. Of the propane employees, 64 are represented by labor unions. We believe that our relations with our employees are satisfactory. Historically, our propane operations hire seasonal workers to meet peak winter demands.

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 1A. RISK FACTORS

An investment in our securities involves a high degree of risk. You should carefully consider the following risk factors included below, together with all of the other information included in, or incorporated by reference into, this report in evaluating an investment in our securities. If any of these risks were to occur, our business, financial condition or results of operations could be adversely affected. In that case, the trading price of our Common Units could decline and you could lose all or part of your investment.

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and other external factors.

The amount of cash we can distribute to holders of our Common Units or other partnership securities depends upon the amount of cash we generate from our operations. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas transported through our transportation pipelines and gathering systems;

- the level of throughput in our processing and treating operations;

the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;

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the price of natural gas;

the relationship between natural gas and NGL prices;

the weather in our operating areas;

the cost to us of the propane we buy for resale and the prices we receive for our propane;

the level of competition from other midstream companies, interstate pipeline companies, propane companies and other energy providers;

the level of our operating costs;

prevailing economic conditions; and

the level of our hedging activities.

In addition, the actual amount of cash we will have available for distribution will also depend on other factors, such as:

the level of capital expenditures we make;

the level of costs related to litigation and regulatory compliance matters;

the cost of acquisitions, if any;

the levels of any margin calls that result from changes in commodity prices;

our debt service requirements;

fluctuations in our working capital needs;

our ability to make working capital borrowings under our credit facilities to make distributions;

our ability to access capital markets;

restrictions on distributions contained in our debt agreements; and

the amount, if any, of cash reserves established by our General Partner in its discretion for the proper conduct of our business.

Because of all these factors, we cannot guarantee that we will have sufficient available cash to pay a specific level of cash distributions to our Unitholders.

Furthermore, you should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses and may not make cash distributions during periods when we record net income.

We may sell additional limited partner interests, diluting existing interests of Unitholders.

Our partnership agreement allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities will have the following effects:

the current proportionate ownership interest of our Unitholders in us will decrease;

the amount of cash available for distribution on each Common Unit or partnership security may decrease;

the relative voting strength of each previously outstanding Common Unit may be diminished; and

the market price of the Common Units or partnership securities may decline.

Future sales of our units or other limited partner interests in the public market could reduce the market price of Unitholders limited partner interests.

As of August 31, 2007, ETE (formerly La Grange Energy, L.P.), owned 62,500,797 Common Units. ETE owns our General Partner. If ETE were to sell and/or distribute its Common Units to the holders of its equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of our outstanding Common Units.

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Our increased debt level and debt agreements may limit our ability to make distributions to Unitholders and our future financial and operating flexibility.

As of August 31, 2007, we had approximately $3.7 billion of consolidated debt outstanding. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;
- covenants contained in our existing debt arrangements require us to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt;
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level; and
- failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability of 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, 2007, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of August 31, 2007, we had approximately $3.7 billion of consolidated debt, of which approximately $2.7 billion was at fixed interest rates and approximately $1.0 billion was at variable interest rates. We have entered interest rate swaps for a total notional amount of $125.0 million, resulting in a net amount of $875.0 million of variable-rate debt at August 31, 2007. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements. To the extent that we have debt with variable interest rates that is not hedged, our results of operations, cash flows and financial condition, could be materially adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner or owners of our General Partner may be factors in credit evaluations of us as a master limited partnership. This is because the General Partner can exercise significant influence over our business activities, including our cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Entities controlling the owner of our General Partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their general and limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us, ETP GP and ETP LLC from the entities that control ETP GP, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of such entities were viewed as substantially lower or more risky than ours.

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The General Partner is not elected by the Unitholders and cannot be removed without its consent.

Unlike the holders of common stock in a corporation, Unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management s decisions regarding our business. Unitholders did not elect our General Partner and will have no right to elect our General Partner on an annual or other continuing basis. Although our General Partner has a fiduciary duty to manage us in a manner beneficial to Energy Transfer Partners, L.P. and the Unitholders, the directors of our General Partner and its General Partner, Energy Transfer Partners, L.L.C., have a fiduciary duty to manage the General Partner and its General Partner in a manner beneficial to the owners of those entities.

Furthermore, if the Unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. The General Partner generally may not be removed except upon the vote of the holders of 66 $^{2}/3$% of the outstanding units voting together as a single class, including units owned by the General Partner and its affiliates. As of August 31, 2007, ETE and its affiliates held approximately 46% of our outstanding units, with an approximately 1% of units held by our officers and directors. Consequently, it could be difficult to remove the General Partner without the consent of the General Partner and our affiliates.

Furthermore, Unitholders voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than the General Partner and its affiliates, cannot be voted on any matter.

The control of our General Partner may be transferred to a third party without Unitholder consent.

The General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the Unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the general partner of our General Partner from transferring its general partner interest in our General Partner to a third party. Any new owner of the General Partner would be in a position to replace the officers of the General Partner with its own choices and to control the decisions taken by such officers.

Unitholders may be required to sell their units to the General Partner at an undesirable time or price.

If at any time less than 20% of the outstanding units of any class are held by persons other than the General Partner and its affiliates, the General Partner will have the right to acquire all, but not less than all, of those 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. The General Partner may assign this purchase right to any of its affiliates or to us.

The interruption of distributions to us from our operating subsidiaries and equity investees may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations. Our only significant assets are the equity interests we own in our operating subsidiaries and equity investees. As a result, we depend upon the earnings and cash flow of our operating subsidiaries and equity investees and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners.

Cost reimbursements due to our General Partner may be substantial and may reduce our ability to pay the distributions to Unitholders.

Prior to making any distributions to our Unithholders, we will reimburse our General Partner for all expenses it has incurred on our behalf. In addition, our General Partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the General Partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the Unitholders. Our General Partner has sole discretion to determine the amount of these expenses and fees.

Unitholders may have liability to repay distributions.

Under certain circumstances Unitholders may have to repay us amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to you if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated Delaware law, will be liable to

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the limited partnership for the distribution amount for three years from the distribution date. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to him at the time he or she became a limited partner if the liabilities could not be determined from the partnership agreement.

Risks Related to Conflicts of Interest

Our partnership agreement limits our General Partner s fiduciary duties to our Unitholders and restricts the remedies available to Unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our General Partner and its affiliates and which reduce the obligations to which our General Partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the fiduciary duties owed by our General Partner to the limited partners. Our partnership agreement:

- permits our General Partner to make a number of decisions in its sole discretion. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our General Partner is entitled to make other decisions in its reasonable discretion ;

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of Unitholders must be fair and reasonable to us and that, in determining whether a transaction or resolution is fair and reasonable, our General Partner may consider the interests of all parties involved, including its own. Unless our General Partner has acted in bad faith, the action taken by our General Partner shall not constitute a breach of its fiduciary duty; and

- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common Unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of ETE. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our Unitholders best interests. In addition, these overlapping executive officers and directors allocate their time among us and ETE. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

The General Partner s absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our Unitholders.

Our partnership agreement requires the General Partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits the General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to Unitholders.

Our General Partner has conflicts of interest and limited fiduciary responsibilities, which may permit our General Partner to favor its own interests to the detriment of Unitholders.

As of August 31, 2007, ETE and its affiliates directly and indirectly owned an aggregate limited partner interest in us of approximately 46% and our officers and directors owned approximately 1% of the limited partner interests in us. Conflicts of interest could arise in the future as a result of relationships between our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our General Partner may favor its own interests and those of its affiliates over the interests of the Unitholders. The nature of these conflicts includes the following considerations:

Remedies available to Unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.

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Our General Partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to the Unitholders.

Our General Partner s affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us.

Our General Partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings and reserves, each of which can affect the amount of cash that is distributed to Unitholders.

Our General Partner determines whether to issue additional units or other equity securities of us.

Our General Partner determines which costs are reimbursable by us.

Our General Partner controls the enforcement of obligations owed to us by it.

Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our General Partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

In some instances our General Partner may borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

The risk of competition with affiliates of our General Partner has increased.

Except as provided in our Partnership Agreement, affiliates of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. On May 7, 2007, Enterprise GP Holdings, L.P. acquired a 34.9% non-controlling equity interest in LE GP, L.L.C., ETE s General Partner. Enterprise GP Holdings, L.P. and its subsidiaries are a North American midstream energy business. As a result, there is greater risk that competition with affiliates of our General Partner could occur, which could adversely impact our results of operations and cash available for distributions.

Risks Related to our Business

The profitability of our midstream and intrastate transportation and storage operations are largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs, which are factors beyond our control and have been volatile.

Income from our midstream and intrastate transportation and storage operations are exposed to risks due to fluctuations in commodity prices. For a portion of the natural gas gathered at the North Texas System, Southeast Texas System and at our HPL System, we purchase natural gas from producers at the wellhead at a price that is at a discount to a specified index price and then gather and deliver the natural gas to pipelines where we typically resell the natural gas at the index price or gas daily average. Generally, the gross margins we realize under these discount-to-index arrangements decrease in periods of low natural gas prices because these gross margins are based on a percentage of the index price.

For a portion of the natural gas gathered and processed at the North Texas System and Southeast Texas System, we enter into percentage-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers. Under percentage-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our

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results of operations. Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs if we are not able to bypass our processing plants and sell the unprocessed natural gas. Under processing fee agreements, we process the gas for a fee. If recoveries are less than those guaranteed the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole with regard to contractual recoveries.

In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, during our fiscal year ended August 31, 2007, the NYMEX settlement price for the prompt month contract ranged from a high of $8.87 per MMBtu to a low of $4.20 per MMBtu. A composite of the Mt. Belvieu average NGLs price based upon our average NGLs composition during our fiscal year ended August 31, 2007 ranged from a high of approximately $1.15 per gallon to a low of approximately $0.83 per gallon. Natural gas prices are subject to significant fluctuations, and we cannot assure you that natural gas prices will remain at the high levels recently experienced.

Our Oasis pipeline, East Texas pipeline, ET Fuel System and HPL System receive fees for transporting natural gas for our customers. Although a significant amount of the pipeline capacity of the East Texas pipeline and various pipeline segments of the ET Fuel System is committed under long-term fee-based contracts, the remaining capacity of our transportation pipelines is subject to fluctuation in demand based on the markets and prices for natural gas and NGLs, which factors may result in decisions by natural gas producers to reduce production of natural gas during periods of lower prices for natural gas and NGLs or may result in decisions by end users of natural gas and NGLs to reduce consumption of these fuels during periods of higher prices for these fuels. Our fuel retention fees are also directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees, and decreases in natural gas prices tend to decrease our fuel retention fees.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions, and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and

the extent of governmental regulation and taxation.

The use of derivative financial instruments could result in material financial losses by us.

From time to time, we have sought to limit a portion of the adverse effects resulting from changes in natural gas and other commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms and by the activities we conduct in our trading operations. To the extent that we hedge our commodity price and interest rate exposures, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, our hedging and trading activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Our success depends upon our ability to continually contract for new sources of natural gas supply.

In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies and natural gas transportation services. We may not be able to obtain additional contracts for natural gas supplies for our natural gas gathering systems, and we may be unable to maintain or increase the levels of natural gas throughput on our transportation pipelines. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity and production of natural gas near our gathering systems or in areas that provide access to our transportation pipelines or markets to which our systems connect. The primary factors affecting our ability to attract customers to our transportation pipelines consist of our access to other natural gas pipelines, natural gas markets, natural gas-fired power plants and other industrial end-users and the level of drilling and production of natural gas in areas connected to these pipelines and systems.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity and production generally decrease as oil and natural gas prices decrease. We have no control over the level of drilling activity in our areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline, sometimes referred to as the decline rate. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. Accordingly, our cash flows will also decline unless we are able to access new supplies of natural gas by connecting additional production to these systems.

Our transportation pipelines are also dependent upon natural gas production in areas served by our pipelines or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. A material decrease in natural gas production in our areas of operation or in other areas that are connected to our areas of operation by third party gathering systems or pipelines, as a result of depressed commodity prices or otherwise, would result in a decline in the volume of natural gas we handle, which would reduce our revenues and operating income. In addition, our future growth will depend, in part, upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our currently connected supplies.

Transwestern derives a significant portion of its revenue from charges to its customers for reservation of capacity, which charges Transwestern receives regardless of whether these customers actually use the reserved capacity. Transwestern also generates revenue from transportation of natural gas for customers without reserved capacity. As the reserves available through the supply basins connected to Transwestern s systems naturally decline, a decrease in development or production activity could cause a decrease in the volume of natural gas available for transmission or a decrease in demand for natural gas transportation on the Transwestern system over the long run. Investments by third parties in the development of new natural gas reserves connected to Transwestern s facilities depend on many factors beyond Transwestern s control.

The volumes of natural gas we transport on our intrastate transportation pipelines may be reduced in the event that the prices at which natural gas is purchased and sold at the Waha Hub, the Katy Hub, the Carthage Hub and the Houston Ship Channel Hub, the four major natural gas trading hubs served by our pipelines, become unfavorable in relation to prices for natural gas at other natural gas trading hubs or in other markets as customers may elect to transport their natural gas to these other hubs or markets using pipelines other than those we operate.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for qualified assets.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream, transportation, storage, propane and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, the acquisition of additional assets and businesses, stand alone development projects or other transactions that we believe will present opportunities to realize synergies and increase our cash flow.

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Consistent with our acquisition strategy, we are continuously engaged in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve our participation in processes that involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot assure you that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in us losing to other bidders more often or acquiring assets at higher prices. Either occurrence would limit our ability to fully execute our growth strategy. Inability to execute our growth strategy may materially adversely impact the market price of our securities.

An impairment of goodwill and intangible assets could reduce our earnings.

At August 31, 2007, our consolidated balance sheet reflected $718.4 million of goodwill and $211.7 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners equity and balance sheet leverage as measured by debt to total capitalization.

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our results of operations and our ability to grow and to increase distributions to Unitholders will depend in part on our ability to make acquisitions that are accretive to our distributable cash flow per unit.

We may be unable to make accretive acquisitions for any of the following reasons, among others:

- because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- because we are unable to raise financing for such acquisitions on economically acceptable terms; or
- because we are outbid by competitors, some of which are substantially larger than us and have greater financial resources and lower costs of capital then we do.

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that we may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;

encounter difficulties operating in new geographic areas or new lines of business;

incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;

be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;

less effectively manage our historical assets, due to the diversion of management s attention from other business concerns; or

incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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If we consummate future acquisitions, our capitalization and results of operations may change significantly. As we determine the application of our funds and other resources, you will not have an opportunity to evaluate the economics, financial and other relevant information that we will consider.

If we do not continue to construct new pipelines, our future growth could be limited.

During the past several years, we have constructed several new pipelines, and are currently involved in constructing several new pipelines. Our results of operations and ability to grow and to increase distributable cash flow per unit will depend, in part, on our ability to construct pipelines that are accretive to our distributable cash flow. We may be unable to construct pipelines that are accretive to distributable cash flow for any of the following reasons, among others:

- we are unable to identify pipeline construction opportunities with favorable projected financial returns;
- we are unable to raise financing for its identified pipeline construction opportunities; or
- we are unable to secure sufficient natural gas transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if we construct a pipeline that we believe will be accretive, the pipeline may in fact adversely affect our results of operations or results from those projected prior to commencement of construction and other factors.

Expanding our business by constructing new pipelines and treating and processing facilities subjects us to risks.

One of the ways that we have grown our business is through the construction of additions to our existing gathering, compression, treating, processing and transportation systems. The construction of a new pipeline or the expansion of an existing pipeline, by adding additional compression capabilities or by adding a second pipeline along an existing pipeline, and the construction of new processing or treating facilities, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital that we will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost. Moreover, our revenues may not increase immediately following the completion of particular projects. For instance, if we build a new pipeline, the construction will occur over an extended period of time, but we may not materially increase our revenues until long after the project s completion. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, new facilities may be unable to attract enough throughput or contracted capacity reservation commitments to achieve our expected investment return, which could adversely affect our results of operations and financial condition. As a result, the success of a pipeline construction project will likely depend upon the level of natural gas exploration and development drilling activity and the demand for pipeline transportation in the areas proposed to be serviced by the project as well as our ability to obtain commitments from producers in this area to utilize the newly constructed pipelines.

We depend on certain key producers for our supply of natural gas on the Southeast Texas System and North Texas System, and the loss of any of these key producers could adversely affect our financial results.

For our fiscal year ended August 31, 2007, ConocoPhillips Company, Enervest Operating, L.L.C, Encana Oil and Gas (USA) Inc., and Lear Energy, LP supplied us with approximately 90% of the Southeast Texas System s natural gas supply. For our fiscal year ended August 31, 2007, Encana Oil and Gas (USA), Inc., EOG Resources, Inc., XTO Energy Inc., and Chesapeake Energy Marketing, Inc. supplied us with approximately 80% of the North Texas System s natural gas supply. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

We depend on key customers to transport natural gas on our East Texas pipeline, ET Fuel System and HPL System.

We have nine- and ten-year fee-based transportation contracts with XTO Energy, Inc. pursuant to which XTO Energy has committed to transport certain minimum volumes of natural gas on our pipelines. We also have an eight-year fee-based transportation contract with TXU Portfolio Management Company, L.P., a subsidiary of TXU Corp., which we refer to as TXU Shipper, to transport natural gas on the ET Fuel System to TXU s electric generating power plants. We have also entered into two eight-year natural gas storage contracts with TXU Shipper to store natural gas at the two

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natural gas storage facilities that are part of the ET Fuel System. Each of the contracts with TXU Shipper may be extended by TXU Shipper for two additional five-year terms. The failure of XTO Energy or TXU Shipper to fulfill their contractual obligations under these contracts could have a material adverse effect on our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

We completed our Cleburne to Carthage pipeline in April 2007. The major shippers through the Cleburne to Carthage pipeline expansion to interstate and intrastate markets are XTO Energy, Inc., EOG Resources, Inc., Chesapeake Energy Marketing, Inc., Encana Marketing (USA), Inc., Quicksilver Resources, Inc., and Leor Energy, L.P. These shippers have long-term contracts ranging from five to 10 years. The failure of these shippers to fulfill their contractual obligations could have a material adverse effect on our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

Federal, state or local regulatory measures could adversely affect our business.

Our midstream and intrastate transportation and storage operations are generally exempt from Federal Energy Regulatory Commission, or (FERC), regulation under the NGA, but FERC regulation still significantly affects our business and the market for our products. The rates, terms and conditions of some of the transportation and storage services we provide on the HPL System, the East Texas pipeline, the Oasis pipeline and the ET Fuel System are subject to FERC regulation under Section 311 of the Natural Gas Policy Act, or NGPA. Under Section 311, rates charged for transportation and storage must be fair and equitable amounts. 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. Should FERC determine not to authorize rates equal to or greater than our currently approved rates we may suffer a loss of revenue. Failure to observe the service limitations applicable to storage and transportation service under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply 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 penalties.

Our intrastate natural gas transportation and storage facilities are subject to state regulation in Texas, New Mexico, Arizona, Louisiana, Utah and Colorado, the states in which we operate these types of pipelines. Our intrastate transportation facilities located in Texas are subject to regulation as common purchasers and as gas utilities by the Texas Railroad Commission, or TRRC. The TRRC s jurisdiction extends to both rates and pipeline safety. The rates we charge for transportation and storage services are deemed just and reasonable under Texas law unless challenged in a complaint. Should a complaint be filed or should regulation become more active, our business may be adversely affected.

Our midstream gathering, processing and intrastate transportation operations are also subject to ratable take and common purchaser statutes in Texas, New Mexico, Arizona, Louisiana, Utah and Colorado. 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 have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. Other state and local regulations also affect our business.

Our storage facilities are also subject to the jurisdiction of the TRRC. Generally, the TRRC has jurisdiction over all underground storage of natural gas in Texas, unless the facility is part of an interstate gas pipeline facility. Because the natural gas storage facilities of the ET Fuel System and HPL System are only connected to intrastate gas pipelines, they fall within the TRRC s jurisdiction and must be operated pursuant to TRRC permit. Certain changes in ownership or operation of TRCC-jurisdictional storage facilities, such as facility expansions and increases in the maximum operating pressure, must be approved by the TRRC through an amendment to the facility s existing permit. In addition, the TRRC must approve transfers of the permits. Texas laws and regulations also require all natural gas storage facilities to be operated to prevent waste, the uncontrolled escape of gas, pollution and danger to life or property. Accordingly, the TRRC requires natural gas storage facilities to implement certain safety, monitoring, reporting and record-keeping measures. Violations of the terms and provisions of a TRRC permit or a TRRC order or regulation can result in the modification, cancellation or suspension of an operating permit and/or civil penalties, injunctive relief, or both.

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The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968, which requires certain pipeline companies to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. Some of our gathering facilities are exempt from the requirements of this Act. In respect to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation have passed or are considering heightened pipeline safety requirements.

Failure to comply with applicable regulations under the NGA, NGPA, Pipeline Safety Act and certain state laws could result in the imposition of administrative, civil and criminal remedies.

The FERC and CFTC are pursuing legal actions against us relating to certain natural gas trading and transportation activities, and related third party claims have been filed against us and ETE.

On July 26, 2007, the Federal Energy Regulatory Commission (the FERC) issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other dates from December 2003 though August 2005, in order to benefit financially from ETP s commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by the McGraw Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha Hub in west Texas on certain dates in December 2005. The FERC s action against us also includes allegations related to our Oasis pipeline, an intrastate pipeline that transports natural gas between the Waha Hub and the Katy Hub near Houston, Texas. The Oasis pipeline also transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority, and subject to FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at negotiated rates, which activity is expected to account for approximately 1.0% of our operating income for our 2007 fiscal year. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based rates would be limited to sales of natural gas to retail customers (such as utilities and other end-users) and sales from our own production, and any other sales of natural gas by us would be required to be made at prices that would be subject to FERC approval. Also on July 26, 2007, the United States Commodity Futures Trading Commission (the CFTC) filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity Exchange Act by attempting to manipulate natural gas prices in the Houston Ship Channel. It is alleged that such manipulation was attempted during the period from late September through early December 2005 to allow us to benefit financially from our commodities derivatives positions.

In its Order and Notice, the FERC is seeking $70.1 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to these matters. The FERC ordered ETP to show cause why the allegations against ETP made in the Order and Notice are not true. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. In its lawsuit, the CFTC is seeking civil penalties of $130,000 per violation, or three times the profit gained from each violation, and other ancillary relief. The CFTC has not specified the number of alleged violations or the amount of alleged profit related to the matters specified in its complaint. On October 15, 2007, ETP filed a motion to dismiss in the United State District Court for the Northern District of Texas on the basis that the CFTC has not stated a valid cause of action under the Commodity Exchange Act.

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It is our position that our trading and transportation activities during the periods at issue complied in all material respects with applicable laws and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC and CFTC hold substantial enforcement authority. At this time, neither we nor ETE is able to predict the final outcome of these matters.

In addition to the FERC and CFTC legal actions, it is also possible that third parties will assert claims against us and ETE for damages related to these matters, which parties could include natural gas producers, royalty owners, taxing authorities, and parties to physical natural gas contracts and financial derivatives based on the *Platts Inside* FERC Houston Ship Channel index during the periods in question. In this regard, two natural gas producers have initiated legal proceedings against us and ETE for claims related to the FERC and CFTC claims. One of the producers has brought suit in Texas state court against us and ETE based on contractual and tort claims relating to alleged manipulation of natural gas prices at the Waha Hub in West Texas and the Houston Ship Channel and is seeking unspecified direct, indirect, consequential and punitive damages. The second producer has brought suit in Texas state court against us and ETE based on contract and tort claims relating to a natural gas purchase contract to which we and this producer are parties. This producer seeks unspecified damages and requests pre-arbitration discovery of information related to our activities prior to further pursuing a claim for manipulation of natural gas prices in the Houston Ship Channel. The producer also seeks to intervene in the FERC proceeding, alleging that it is entitled to a FERC-ordered refund of $5.9 million, plus interest and costs. In addition, a plaintiff has filed a putative class action against us in the United States District Court for the Southern District of Texas. This suit alleges that we unlawfully manipulated the price of natural gas futures and options contracts on the New York Mercantile Exchange, or NYMEX, in violation of the Commodity Exchange Act, that we have the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, Waha, and Permian hubs, in order to benefit our natural gas physical and financial trading positions. The suit alleges that this unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels between December 29, 2003 and December 31, 2005, causing unspecified damages to plaintiff and all others who purchased and/or sold natural gas futures and options contracts on NYMEX during that period.

We are expensing the legal fees, consultants fees and related expenses relating to these matters in the periods in which such expenses are incurred. In addition, our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the outcome of these matters; however, it is possible that the amount we become obligated to pay as a result of the final resolution of these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of our existing accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obligated to pay as a result of the final resolution of these matters is greater than the amount of our existing accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available for distributions either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

Transwestern is subject to laws, regulations and policies governing the rates it is allowed to charge for its services.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect Transwestern s ability to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs. Natural gas companies must charge rates that are deemed to be just and reasonable by FERC. The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to the Natural Gas Act, existing rates may be challenged by complaint and rate increases proposed by the natural gas company may be challenged by protest. Further, other than for rates set under market-based rate authority, rates must be cost-based and the FERC may order refunds of amounts collected under rates that were in excess of a just and reasonable level. Transwestern filed a general rate case in September 2006. The rates in this proceeding were settled and are final and no longer subject to refund. Transwestern is not required to file new cost-based rates until October 2011. In addition, shippers (other than shippers who have agreed not to challenge our tariff rates through 2010 pursuant to our recent settlement agreement with these shippers) may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint. Any successful complaint or protest against Transwestern s rates could reduce our revenues associated with providing transmission services on a prospective basis. We cannot assure you that we will be able to recover all of Transwestern s costs through existing or future rates.

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The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes in their regulated rates has been subject to extensive litigation before FERC and the courts, and the FERC s current policy is subject to future refinement or change.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before FERC and the courts for a number of years. In July 2004, the D.C. Circuit issued its opinion in *BP West Coast Products, LLC* v. FERC, which upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, Santa Fe Pacific Pipeline, or SFPP, were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification to those rates. The Court also vacated the portion of the FERC s decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its Unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as, or owned by, tax-pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issues in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income allowance. Further, in the December 2005 order, the FERC concluded that for tax allowance purposes, the FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal rate of 28%. The FERC indicated that it would address the income tax allowance issues further in the context of SFPP s compliance filing submitted in March 2006. In December 2006, the FERC ruled on some of the issues raised as to the March 2006 SFPP compliance filing, upholding most of its determinations in the December 2005 order. FERC did revise its rebuttable presumption as to corporate partners marginal tax rate from 35% to 34%. The FERC s *BP West Coast* remand decision and the new income tax allowance policy were appealed to the D.C. Circuit. In May 2007, the D.C. Circuit affirmed FERC s favorable income tax allowance policy. As a result, we remain eligible to include an allowance in the tariff rates we charge for natural gas transportation on our Transwestern interstate pipeline system, subject to our ability to demonstrate compliance with FERC s policy. The specific terms and application of that policy remain subject to future refinement or change by FERC and the courts. As FERC has recently approved our tariff rates specified in a settlement agreement with shippers, the allowance for income taxes as a cost-of-service element in our tariff rates is not subject to challenge prior to the expiration of our settlement agreement in 2011.

Transwestern is subject to laws, regulations and policies governing terms and conditions of service, which control many aspects of its business.

In addition to rate oversight, FERC s regulatory authority extends to many other aspects of Transwestern s business and operations, including:

- operating terms and conditions of service;
- the types of services Transwestern may offer to its customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;

accounts and records; and

relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. Future changes to laws, regulations and policies in these areas may impair Transwestern s ability to compete for business or increase the cost and burden of operation.

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Failure to comply with all applicable FERC-administered statutes, rules, regulations and orders, could bring substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1.0 million per day for each violation.

Finally, we cannot give any assurance regarding the likely future regulations under which we will operate Transwestern or the effect such regulation could have on our business, financial condition, and results of operations.

Our business involves hazardous substances and may be adversely affected by environmental regulation.

Our natural gas as well as our propane operations are subject to stringent federal, state, and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of permits for our operations, result in capital expenditures to manage, limit, or prevent emissions, discharges, or releases of various materials from our pipelines, plants, and facilities, and impose substantial liabilities for pollution resulting from our operations. Several governmental authorities, such as the U.S. Environmental Protection Agency, have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctive relief.

We may incur substantial environmental costs and liabilities because the underlying risk are inherent to our operations. Joint and several, strict liability may be incurred under environmental laws and regulations in connection with discharges or releases of petroleum hydrocarbons or wastes on, under, or from our properties and facilities, many of which have been used for industrial activities for a number of years. Private parties, including the owners of properties through which our gathering systems pass or facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. The total accrued future estimated cost of remediation activities relating to our Transwestern pipeline operations is approximately $12.3 million, which activities are expected to continue for several years.

Changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport disposal or remediation requirements could have a material adverse effect on our operations or financial position. For instance, the Texas Commission on Environmental Quality, or TCEQ, recently adopted a rule further restricting the level of nitrogen oxides, or NOx, that may be emitted from stationary gas-fired reciprocating internal combustion engines located in counties comprising the Dallas-Fort Worth eight hour ozone non-attainment area. As a result of the adoption of this rule, by March 1, 2009, we must either modify or replace seven owned and 21 leased compressor units currently located in the Dallas-Fort Worth non-attainment area that do not satisfy the TCEQ s new, more stringent NOx emission limitations. We are evaluating our options to comply with this rule and thus the costs to comply currently are not reasonably estimable but such costs ultimately could be material to our operations. Also, the U.S. Congress is actively considering legislation and more than a dozen states have already taken legal measures to reduce emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere. Moreover, the U.S. Supreme Court recently decided, in *Massachusetts, et al. v. EPA,* that greenhouse gases fall within the federal Clean Air Act s definition of air pollutant, which could result in the regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our services.

Any reduction in the capacity of, or the allocations to, our shippers in interconnecting, third-party pipelines could cause a reduction of volumes transported in our pipelines, which would adversely affect our revenues and cash flow.

Users of our pipelines are dependent upon connections to and from third-party pipelines to receive and deliver natural gas and NGLs. Any reduction in the capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes being transported in our pipelines. Similarly, if additional shippers begin transporting volumes of natural gas and NGLs over interconnecting pipelines, the allocations to existing shippers in these pipelines would be reduced, which could also reduce volumes transported in our pipelines. Any reduction in volumes transported in our pipelines would adversely affect our revenues and cash flow.

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We encounter competition from other midstream, transportation and storage companies and propane companies.

We experience competition in all of our markets. Our principal areas of competition include obtaining natural gas supplies for the Southeast Texas System, North Texas System and HPL System and natural gas transportation customers for our transportation pipeline systems. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas. The Southeast Texas System competes with natural gas gathering and processing systems owned by DCP Midstream, LLC. The North Texas System competes with Crosstex North Texas Gathering, LP and Devon Gas Services, LP for gathering and processing. The East Texas pipeline competes with other natural gas transportation pipelines that serve the Bossier Sands area in east Texas and the Barnett Shale region in north Texas. The ET Fuel System and the Oasis pipeline compete with a number of other natural gas pipelines, including interstate and intrastate pipelines that link the Waha Hub. The ET Fuel System competes with other natural gas transportation pipelines serving the Dallas/Ft. Worth area and other pipelines that serve the east central Texas and south Texas markets. Pipelines that we compete with in these areas include those owned by Atmos Energy Corporation, Enterprise Products Partners, L.P., and Enbridge, Inc. Some of our competitors may have greater financial resources and access to larger natural gas supplies than we do.

The acquisitions of the HPL System and the Transwestern pipeline increased the number of interstate pipelines and natural gas markets to which we have access and expanded our principal areas of competition to areas such as southeast Texas and the Texas Gulf Coast. As a result of our expanded market presence and diversification, we face additional competitors, such as major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas, that may have greater financial resources and access to larger natural gas supplies than we do.

The interstate pipeline business of Transwestern competes with those of other interstate and intrastate pipeline companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service and the flexibility and reliability of service. Natural gas competes with other forms of energy available to our customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the levels of natural gas transportation volumes in the areas served by our pipelines.

Our propane business competes with a number of large national and regional propane companies and several thousand small independent propane companies. Because of the relatively low barriers to entry into the retail propane market, there is potential for small independent propane retailers, as well as other companies that may not currently be engaged in retail propane distribution, to compete with our retail outlets. As a result, we are always subject to the risk of additional competition in the future. Generally, warmer-than-normal weather further intensifies competition. Most of our propane retail branch locations compete with several other marketers or distributors in their service areas. The principal factors influencing competition with other retail propane marketers are:

- price,
- reliability and quality of service,
- responsiveness to customer needs,
- safety concerns,
- long-standing customer relationships,
- the inconvenience of switching tanks and suppliers, and

the lack of growth in the industry.

The inability to continue to access tribal lands could adversely affect Transwestern s ability to operate its pipeline system and the inability to recover the cost of right-of-way grants on tribal lands could adversely affect its financial results.

Transwestern s ability to operate its pipeline system on certain lands held in trust by the United States for the benefit of a Native American Tribe, which we refer to as tribal lands, will depend on its success in maintaining existing rights-of-way and obtaining new rights-of-way on those tribal lands. Securing additional rights-of-way is also critical to Transwestern s ability to pursue expansion projects. We cannot provide any assurance that Transwestern will be able to acquire new rights-of-way on tribal lands or maintain access to existing rights-of-way upon the expiration of the current grants. Our financial position could be adversely affected if the costs of new or extended right-of-way grants cannot be recovered in rates.

We are exposed to the credit risk of our customers, and an increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our Unitholders.

The risks of nonpayment and nonperformance by our customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any substantial increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our Unitholders.

We may be unable to bypass the processing plants, which could expose us to the risk of unfavorable processing margins.

Because of our ownership of the Oasis pipeline and ET Fuel System, we can generally elect to bypass the processing plant when processing margins are unfavorable and instead deliver pipeline-quality gas by blending rich gas from the gathering systems with lean gas transported on the Oasis pipeline and ET Fuel System. In some circumstances, such as when we do not have a sufficient amount of lean gas to blend with the volume of rich gas that we receive at the processing plant, we may have to process the rich gas. If we have to process when processing margins are unfavorable, our results of operations will be adversely affected.

We may be unable to retain existing customers or secure new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets we serve.

For our fiscal year ended August 31, 2007, approximately 22.4% of our sales of natural gas were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are increasingly reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

Our storage business depends on neighboring pipelines to transport natural gas.

To obtain natural gas, our storage business depends on the pipelines to which they have access. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on those pipelines or adverse change in their terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our facilities and a corresponding material adverse effect on our storage revenues. In addition, the rates charged by those interconnected pipelines for transportation to and from our facilities affect the utilization and value of our storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

Our pipeline integrity program may cause us to incur significant costs and liabilities.

Our operations are subject to regulation by the U.S. Department of Transportation, or DOT, under the Pipeline Hazardous Materials Safety Administration (PHMSA), pursuant to which the PHMSA has established regulations relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities.

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Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements for its existing transportation assets other than the Transwestern pipeline will result in capital costs of $7.9 million during the period between the remainder of calendar year 2007 through 2008, as well as operating and maintenance costs of $13.1 million during that period. During this same time period, we estimate that we will incur pipeline integrity operating and on-going annual maintenance capital costs of $18.7 million with respect to our Transwestern pipeline. Through August 31, 2007, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2010. Through August 31, 2007, a total of $13.4 million of capital costs and $11.8 million of operating and maintenance costs have been incurred for pipeline integrity testing for transportation assets other than Transwestern. Through August 31, 2007, a total of $2.9 million of capital costs and $0.1 million of operating and maintenance costs have been incurred for pipeline integrity testing for Transwestern. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Since weather conditions may adversely affect demand for propane, our financial conditions may be vulnerable to warm winters.

Weather conditions have a significant impact on the demand for propane for heating purposes because the majority of our customers rely heavily on propane as a heating fuel. Typically, we sell approximately two-thirds of our retail propane volume during the peak-heating season of October through March. Our results of operations can be adversely affected by warmer winter weather which results in lower sales volumes. In addition, to the extent that warm weather or other factors adversely affect our operating and financial results, our access to capital and our acquisition activities may be limited. Variations in weather in one or more of the regions where we operate can significantly affect the total volume of propane that we sell and the profits realized on these sales. Agricultural demand for propane may also be affected by weather, including periods of unseasonably cold or hot periods or dry weather conditions which may impact agricultural operations.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our Common Units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

If one or more facilities that are owned by us, or that deliver natural gas or other products to us, are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our Unitholders and, accordingly, adversely affect the market price of our Common Units.

We believe that we maintain adequate insurance coverage, although insurance will not cover many types of interruptions that might occur. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

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Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation s pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities or pipelines or those of our customers could have a material adverse effect on our business.

Sudden and sharp propane price increases that cannot be passed on to customers may adversely affect our profit margins.

The propane industry is a margin-based business in which gross profits depend on the excess of sales prices over supply costs. As a result, our profitability is sensitive to changes in energy prices, and in particular, changes in wholesale prices of propane. When there are sudden and sharp increases in the wholesale cost of propane, we may be unable to pass on these increases to our customers through retail or wholesale prices. Propane is a commodity and the price we pay for it can fluctuate significantly in response to changes in supply or other market conditions over which we have no control. In addition, the timing of cost pass-throughs can significantly affect margins. Sudden and extended wholesale price increases could reduce our gross profits and could, if continued over an extended period of time, reduce demand by encouraging our retail customers to conserve their propane usage or convert to alternative energy sources.

Our results of operations and our ability to make distributions or pay interest or principal on debt securities could be negatively impacted by price and inventory risk related to our propane business and management of these risks.

We generally attempt to minimize our cost and inventory risk related to our propane business by purchasing propane on a short-term basis under supply contracts that typically have a one-year term and at a cost that fluctuates based on the prevailing market prices at major delivery points. In order to help ensure adequate supply sources are available during periods of high demand, we may purchase large volumes of propane during periods of low demand or low price, which generally occur during the summer months, for storage in our facilities, at major storage facilities owned by third parties or for future delivery. This strategy may not be effective in limiting our cost and inventory risks if, for example, market, weather or other conditions prevent or allocate the delivery of physical product during periods of peak demand. If the market price falls below the cost at which we made such purchases, it could adversely affect our profits.

Some of our propane sales are pursuant to commitments at fixed prices. To mitigate the price risk related to our anticipated sales volumes under the commitments, we may purchase and store physical product and/or enter into fixed price over-the-counter energy commodity forward contracts and options. Generally, over-the-counter energy commodity forward contracts have terms of less than one year. We enter into such contracts and exercise such options at volume levels that we believe are necessary to manage these commitments. The risk management of our inventory and contracts for the future purchase of product could impair our profitability if the customers do not fulfill their obligations.

We also engage in other trading activities, and may enter into other types of over-the-counter energy commodity forward contracts and options. These trading activities are based on our management s estimates of future events and prices and are intended to generate a profit. However, if those estimates are incorrect or other market events outside of our control occur, such activities could generate a loss in future periods and potentially impair our profitability.

We are dependent on our principal propane suppliers, which increases the risk of an interruption in supply.

During fiscal 2007, we purchased approximately 23% and 22% of our propane from Targa Liquids and Enterprise, respectively. In addition, we purchased approximately 21% of our propane from M-P Energy Partnership, a Canadian partnership in which we owned through August 31, 2007 a 60% interest. Enterprise is a subsidiary of Enterprise GP, an entity that owns approximately 17.6% of ETE s outstanding Common Units and a 34.9% non-controlling interest in the General Partner of ETE, and is therefore considered to be an affiliate of us. Titan purchases substantially all of its propane from Enterprise pursuant to an agreement that expires in 2010. If supplies from these sources were interrupted, the cost of procuring replacement supplies and transporting those supplies from alternative locations might be materially higher and, at least on a short-term basis, margins could be adversely affected. Supply from Canada is subject to the additional risk of disruption associated with foreign trade such as trade restrictions, shipping delays and political, regulatory and economic instability.

Historically, a substantial portion of the propane that we purchase has originated from one of the industry s major markets located in Mt. Belvieu, Texas and has been shipped to us through major common carrier pipelines. Any significant interruption in the service at Mt. Belvieu or other major market points, or on the common carrier pipelines we use, would adversely affect our ability to obtain propane.

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Competition from alternative energy sources may cause us to lose propane customers, thereby reducing our revenues.

Competition in our propane business from alternative energy sources has been increasing as a result of reduced regulation of many utilities. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and the availability of natural gas in many areas that previously depended upon propane could cause us to lose customers, thereby reducing our revenues. Fuel oil also competes with propane and is generally less expensive than propane. In addition, the successful development and increasing usage of alternative energy sources could adversely affect our operations.

Energy efficiency and technological advances may affect the demand for propane and adversely affect our operating results.

The national trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, has decreased the demand for propane by retail customers. Stricter conservation measures in the future or technological advances in heating, conservation, energy generation or other devices could adversely affect our operations.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to Unitholders.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we would likely pay additional state income taxes as well. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders. Because a tax would then be imposed upon us as a corporation, our cash available for distribution to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to our Unitholders would be reduced.

The tax treatment of our structure is subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The U.S. federal income tax treatment of Unitholders depends in some instances on determinations of fact and interpretations of complex provisions of U.S. federal income tax law. You should be aware that the U.S. federal income tax rules are constantly under review by persons involved in the legislative process, the IRS, and the U.S. Treasury Department, frequently resulting in revised interpretations of established concepts, statutory changes, revisions to Treasury Regulations and other modifications and interpretations. The present U.S. federal income tax treatment of an investment in our Common Units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation (referred to as the Qualifying Income Exception), affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our Common Units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Internal Revenue Code section 7704(d). It is possible that these efforts could result in changes to the existing U.S. federal tax laws that affect publicly traded partnerships, including us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our Common Units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

If the IRS contests the federal income tax positions we take, the market for our Common Units may be adversely affected, and the costs of any such contest will reduce cash available for distributions to our Unitholders.

The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us reducing the cash available for distribution to our Unitholders.

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

Because our Unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, Unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from the taxation of their share of our taxable income. In such case, Unitholders would still be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income regardless of the amount, if any, of any cash distributions they receive from us.

Tax gain or loss on disposition of our Common Units could be more or less than expected.

If Unitholders sell their Common Units, they will recognize a gain or loss equal to the difference between the amount realized and the tax basis in those Common Units. Because distributions in excess of the Unitholder s allocable share of our net taxable income decrease the Unitholder s tax basis in their Common Units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the Unitholder if they sell such units at a price greater than their tax basis in those units, even if the price received is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a Unitholder s share of our nonrecourse liabilities, if a Unitholder sells units, the Unitholder may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning Common Units that may result in adverse tax consequences to them.

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, may be taxable to them as unrelated

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business taxable income. Distributions to non-U.S. persons will be reduced by withholding taxes, at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and generally pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our Common Units.

We treat each purchaser of Common Units as having the same tax benefits without regard to the actual Common Units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the Common Units.

To maintain the uniformity of the economic and tax characteristics of our Common Units, we have adopted certain depreciation and amortization positions that are inconsistent with existing Treasury Regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our Unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding units. A subsequent holder of those units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). But, because we cannot identify these units once they are traded by the initial holder, we do not give any subsequent holder of a unit any such amortization deduction. This approach understates deductions available to those Unitholders who own those units and may result in those Unitholders believing that they have a higher tax basis in their units than is actually the case. This, in turn, may result in those Unitholders reporting less gain or more loss on a sale of their units than is actually the case.

The IRS may challenge the manner in which we calculate our Unitholder s basis adjustment under Section 743(b). If so, because neither we nor a Unitholder can identify the units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all Unitholders selling units within the period under audit as if all Unitholders owned such units.

Any position we take that is inconsistent with applicable Treasury Regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our Unitholders.

A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our Unitholders. It also could affect the gain from a Unitholder s sale of Common Units and could have a negative impact on the value of the Common Units or result in audit adjustments to our Unitholders tax returns without the benefit of additional deductions. Moreover, because one of our subsidiaries that is organized as a C corporation for federal income tax purposes owns units in us, a successful IRS challenge could result in this subsidiary having more tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to you.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and our public Unitholders. The IRS may challenge this treatment, which could adversely affect the value of our Common Units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our Unitholders and our General Partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our Common Units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain Unitholders and our General Partner, which may be unfavorable to such Unitholders. Moreover, under our current valuation methods, subsequent purchasers of our Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our General Partner and certain of our Unitholders.

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

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

Our partnership will be considered to have terminated for federal income tax purposes if transfers of units within a twelve month period constitute the sale or exchange of 50% or more of our capital and profit interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of our capital and profits interests within the prior twelve month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

Based on the information currently available to us, we believe that we exceeded the 50% threshold on May 7, 2007, and, as a result, we have determined that our partnership has terminated for federal tax income purposes on that date. This termination does not affect our classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income for federal income tax purposes. This termination will require us to close our taxable year, make new elections as to various tax matters and reset the depreciation schedule for our depreciable assets for federal income tax purposes. The resetting of our depreciation schedule will result in a deferral of the depreciation deductions allowable in computing the taxable income allocated to our Unitholders. However, certain elections we will make in connection with this tax termination will allow us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of our Unitholders, which deductions had not previously been utilized in computing taxable income allocable to our Unitholders. As a consequence of these factors, we currently estimate, based on our current distribution levels and various assumptions regarding our gross income and capital expenditures during these respective periods, that a recent purchaser of units would be allocated taxable income of between 10% and 20% of the cash expected to be distributed to such Unitholder for the 2007 calendar year and less than 10% of the cash expected to be distributed to such Unitholder for the 2008 calendar year. We estimate, based on the same assumptions, that a Unitholder who purchased units prior to our combination with Heritage Propane, L.P. in January 2004 would be allocated taxable income of approximately 90% of the cash distributed to him for the 2007 calendar year and approximately 50% of the cash distributed to him for the 2008 calendar year. Beginning in 2008, we estimate, based on the same assumptions, that a new purchaser of our units, and current Unitholders who purchased our units more recently, would be allocated taxable income of less than 10% of the cash distributed to them for the 2008 calendar year. In the case of a Unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our income or loss being includable in their taxable income for the year of termination.

You will likely be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our Common Units.

In addition to federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not live in any of those jurisdictions. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Substantially all of our pipelines, which are located in Arizona, New Mexico, Colorado, Utah, Texas and Louisiana, are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which

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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.

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 one office building for our executive office in Dallas, Texas and one office building in Helena, Montana for the administration of our propane operations. We also lease office facilities in Houston, Texas, San Antonio, Texas, Florence, Kentucky, Tulsa, Oklahoma, and Denver, Colorado. 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 operate bulk storage facilities at approximately 440 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 48.0 million gallons of aboveground storage capacity at our various propane plant sites and have leased an aggregate of approximately 31 million gallons of underground storage facilities in Michigan, Arizona, New Mexico and Texas and smaller storage facilities in other locations. 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, 2007, we utilized approximately 60 transport truck tractors, 60 transport trailers, 20 railroad tank cars, 1,700 bobtails and 2,700 other delivery and service vehicles, all of which we own. As of August 31, 2007, we owned approximately 1,130,000 customer storage tanks with typical capacities of 120 to 1,000 gallons that are leased or available for lease to customers. HOLP s 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 and Titan 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, V-1 Propane, Coast Gas, Empiregas, Flame Propane, Graves Propane, Synergy Gas. 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

We are not aware of any material legal or governmental proceedings against our Operating Partnerships, or contemplated to be brought against our Operating Partnerships, under the various environmental protection statutes to which they are subject.

FERC/CFTC and Related Matters. On July 26, 2007, the Federal Energy Regulatory Commission (the FERC) issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other dates from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha Hub and the Katy Hub near Houston, Texas. Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at negotiated rates, which activity is expected to account for approximately 1.0% of our operating income for our 2007 fiscal year. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based rates would be limited to sales of natural gas to retail customers (such as utilities and other end users) and sales from our own production, and any other sales of natural gas by us would be required to be made at prices that would be subject to the FERC approval. Also on July 26, 2007, the United States Commodity Futures Trading Commission (the CFTC) filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity Exchange Act by attempting to manipulate natural gas prices in the Houston Ship Channel. It is alleged that such manipulation was attempted during the period from late September through early December 2005 to allow us to benefit financially from our commodities derivatives positions.

In its Order and Notice, the FERC is seeking $70.1 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to these matters. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. In its lawsuit, the CFTC is seeking civil penalties of $130,000 per violation, or three times the profit gained from each violation, and other ancillary relief. The CFTC has not specified the number of alleged violations or the amount of alleged profit related to the matters specified in its complaint. On October 15, 2007, ETP filed a motion to dismiss in the United State District Court for the Northern District of Texas on the basis that the CFTC has not stated a valid cause of action under the Commodity Exchange Act.

It is our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC and CFTC hold substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

In addition to the FERC and CFTC legal actions, it is also possible that third parties will assert claims against us for damages related to these matters, which parties could include natural gas producers, royalty owners, taxing authorities, and parties to physical natural gas contracts and financial derivatives based on the Platts *Inside FERC* Houston Ship Channel index during the periods in question. In this regard, two natural gas producers have initiated legal proceedings against us, one of which is seeking an unspecified amount of direct, indirect, consequential and punitive damages for alleged manipulation of natural gas prices at the Waha Hub in West Texas and the other is seeking to obtain discovery of information related to our activities prior to further pursuing a claim for manipulation of natural gas prices in the

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Houston Ship Channel. In addition, a plaintiff has filed a putative class action which purports to be brought on behalf of natural gas traders who purchased and/or sold natural gas futures and options on the New York Stock Mercantile Exchange between December 29, 2003 and December 31, 2005.

We are expensing the legal fees, consultants fees and related expenses relating to these matters in the periods in which such expenses are incurred. In addition, our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the outcome of these matters; however, it is possible that the amount we become obliged to pay as a result of the final resolution of these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of our existing accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our existing accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available for distributions either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariffs, which were filed with and approved by the FERC. As a result, Transwestern believes that it has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. Transwestern does not believe the outcome of this case will have a material adverse effect on its financial position, results of operations or cash flows. A hearing was held on April 24, 2007 regarding Transwestern s Supplemental Brief for Attorneys fees which was filed on January 8, 2007 and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg s opening brief was due July 31, 2007. Appellee s opposition brief is due November 21, 2007.

Transwestern Trespass Actions. Transwestern is managing one threatened trespass action related to right of way (ROW) on Tribal or allottee land. The threatened action concerns 5,100 feet of ROW on private allotments within the Laguna Pueblo that expired on December 28, 2002. Transwestern received a letter dated March 19, 2003 from the United States Department of the Interior, Bureau of Indian Affairs (BIA) on behalf of the two allottees asserting trespass. Transwestern s legal exposure related to this matter is not currently determinable. Negotiations are ongoing on this matter.

Another action involves an agreement with the BIA covering 44 miles of ROW on a total of 68 Navajo allotments. This ROW agreement expired on January 1, 2004. One allottee sent a letter dated January 16, 2004 to the BIA claiming Transwestern trespassed and that allotee s claim of trespass has been settled and his consent to use the property has been acquired. Transwestern filed a renewal application with the BIA during October 2002, and has received two grants from the BIA for allotted lands in New Mexico and Arizona, which are effective through December 31, 2023.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies, and American Electric Power Corporation (AEP), were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A 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. This litigation is referred to 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

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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.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. Certain claims, suits and complaints arising in the ordinary course of business have been filed or are pending against us. Although any litigation is inherently uncertain, for each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of August 31, 2007 and 2006, an accrual of $30.3 million and $32.1 million, respectively, was recorded as accrued and other current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters. (See Note 9 to our consolidated financial statements.)

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

None during the quarter ended August 31, 2007. See Note 6 to our consolidated financial statements.

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.

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	Price Range		Cash
	High	Low	Distribution (1)
Fiscal Year 2007			
Fourth Quarter Ended August 31, 2007	$ 64.00	$ 40.50	$ 0.82500
Third Quarter Ended May 31, 2007	$ 63.40	$ 54.76	$ 0.80625
Second Quarter Ended February 28, 2007	$ 56.00	$ 49.23	$ 0.78750
First Quarter Ended November 30, 2006	$ 54.64	$ 43.60	$ 0.76875

	Price Range		Cash Distribution
	High	Low	(1)
Fiscal Year 2006			
Fourth Quarter Ended August 31, 2006	$ 48.00	$ 42.02	$ 0.75000
Third Quarter Ended May 31, 2006	$ 45.85	$ 35.31	$ 0.63750
Second Quarter Ended February 28, 2006	$ 37.98	$ 33.55	$ 0.58750
First Quarter Ended November 30, 2005	$ 37.72	$ 30.53	$ 0.55000

(1) Distributions are shown in the quarter with respect to which they relate. 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.

On June 20, 2006, we declared a special distribution of $0.0325 per Common and Class F Unit related to the proceeds received by the Partnership in connection with the SCANA litigation settlement (see Notes 6 and 9 to the consolidated financial statements) which was paid on July 14, 2006 to the holders of record of the Partnership s Common and Class F Units as of the close of business on June 30, 2006. In connection with this distribution, we also declared and made a $3.6 million distribution to the holder of our Class C Units, which amount represents the amount that would have otherwise distributed to our General Partner.

Description of Units

As of September 1, 2007, there were approximately 77,443 individual Common Unitholders, which includes Common Units held in street name. Our Common Units represent limited partner interests in our 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, 2007, we had 136,981,221 Common Units outstanding, of which 73,383,908 were held by the public, 62,500,797 were held by ETE or its affiliates, 1,308 were held by FHM Investments, L.L.C., and 1,095,208 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). The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

Class E Units. In conjunction with our purchase of the capital stock of Heritage Holdings in January 2004, the 4,426,916 Common Units held by Heritage Holdings were converted into 4,426,916 Class E Units. Pursuant to our two-for-one unit split completed on March 15, 2005, there are currently 8,853,832 Class E Units outstanding, all of which are owned by Heritage Holdings. The Class E Units generally do not have any voting rights. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. Management plans to leave the Class E Units outstanding indefinitely.

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 Distributions of Available Cash from Operating Surplus below.

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.

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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 our partnership agreement previously incorporated by reference as an exhibit to this report.

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.

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

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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

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.

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.

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The total amount of distributions declared during the years ended August 31, 2007 and 2006 is as follows:

	2007	2006
Limited Partners -		
Common Units	$ 366,180	$ 248,237
Class C Units		3,599
Class F Units		3,232
Class G Units	40,598	
General Partners -		
2% Ownership	12,701	6,981
Incentive Distribution Rights	203,069	81,722
	$ 622,548	$ 343,771

All distributions were made from Available Cash from the Partnership s operating surplus.

Securities Authorized for Issuance Under Equity Compensation Plans

Please see Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters of this annual report.

Changes in Securities and Recent Sales of Unregistered Securities

None during the quarter ended August 31, 2007. See Note 6 to our consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

In January 2004, we combined the natural gas midstream and transportation operations of ETC OLP with the retail propane operations of Heritage Propane Partners, L.P. (Heritage)(the Energy Transfer Transactions). In March 2004, Heritage changed its name to Energy Transfer Partners, L.P. Although Heritage 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 in January 2004, 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.

In April 2005, we sold the Elk City System and accounted for the sale as discontinued operations. As such, the results presented for the eleven months ended August 31, 2003 and the year ended August 31, 2004 below have been restated to report the results of the Elk City System as discontinued operations.

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.

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	Year Ended August 31, 2007	2006	2005	2004	Eleven Months Ended August 31, 2003 (a)
Statement of Operations Data:					
Revenues:					
Midstream segment	$ 2,853,496	$ 4,223,544	$ 3,246,772	$ 1,880,663	$ 899,086
Intrastate transportation and storage segment	3,915,932	5,013,224	2,608,108	113,938	41,500
Interstate transportation segment	178,663				
Eliminations	(1,562,199)	(2,359,256)	(471,255)	(27,798)	(9,559)
Retail propane segment	1,284,867	879,556	709,473	349,344	
Other	121,278	102,028	75,700	30,810	
Total revenues	6,792,037	7,859,096	6,168,798	2,346,957	931,027
Gross margin	1,713,831	1,290,780	787,283	365,533	105,589
Depreciation and amortization	179,162	117,415	92,943	48,599	11,870
Operating income	829,652	642,871	312,051	139,089	55,595
Interest expense	175,563	113,857	93,017	41,190	12,456
Income from continuing operations before income tax expense	689,797	541,772	208,678	97,470	45,063
Income tax expense (b)	13,658	25,920	7,295	4,481	4,432
Income from continuing operations	676,139	515,852	201,383	92,989	40,631
Basic income from continuing operations per unit (c)	3.32	3.16	1.51	1.62	3.01
Diluted income from continuing operations per limited partner unit (c)	3.31	3.15	1.50	1.62	3.01
Cash distribution per unit (d)	3.19	2.56	1.89	1.46	
Balance Sheet Data (at period end):					
Current assets	1,041,093	1,301,804	1,446,572	480,435	223,897
Total assets	7,708,428	5,455,013	4,415,458	2,327,104	602,103
Current liabilities	924,217	1,016,490	1,239,426	397,037	169,473
Long-term debt	3,626,977	2,589,124	1,675,705	1,070,871	196,000
Partners capital/Stockholders equity	3,039,833	1,736,862	1,326,192	746,980	181,088
Other Financial Data:					
Cash flow provided by operating activities	1,112,732	543,884	169,418	162,695	70,206
Cash flow used in investing activities	(2,158,090)	(1,244,406)	(1,133,749)	(790,737)	(341,258)
Cash flow provided by financing activities	1,088,022	701,649	907,500	656,665	324,174
Capital expenditures:					
Maintenance (accrual basis)	89,226	51,826	41,054	22,514	7,691
Growth (accrual basis)	998,075	677,861	155,405	87,174	4,223
Acquisition	90,695	586,185	1,131,844	681,835	340,187

(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 such date, Oasis Pipe Line s results of operations are consolidated with ETC OLP as a wholly-owned subsidiary.

(b) As a partnership, we are not subject to income taxes. However, our subsidiaries, Oasis Pipe Line, Heritage Holdings, Heritage Service Corporation, and Titan Propane Services, Inc. are corporations subject to income taxes.

(c) See Note 4 to our consolidated financial statements for a discussion of the computation of earnings per unit.

(d) The cash distribution per unit for fiscal year 2006 includes the Special SCANA distribution of $0.0325 per unit discussed in Notes 6 and 9 of our consolidated financial statements.

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included in Item 8 of this report. Our Management s Discussion and Analysis includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A Risk Factors included in this report.

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Overview

General

Our business activities are primarily conducted through our Operating Partnerships. The Partnership and the Operating Partnerships are sometimes referred to collectively in this report as we , us , 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 natural gas midstream and transportation and storage businesses (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 our existing infrastructure and acquiring certain additional businesses or assets. The actual amount of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

During the past several years we have been successful in completing several transactions that have been accretive to our Unitholders. First and foremost was the completion of the Energy Transfer Transactions, which was the combination of the retail propane operations of Heritage and the midstream and intrastate transportation and storage operations of ETC OLP in January 2004. Subsequent to the combination we have made numerous significant acquisitions in both our natural gas and propane operations, most notably the following:

- ET Fuel System in June 2004
- HPL System in January 2005
- Titan Propane in June 2006
- Transwestern in December 2006

Concurrently, we have also made significant investments in internal growth projects which we believe will provide additional cash flow to our Unitholders in years to come.

Our principal operations are conducted in the following significant segments:

- Midstream
- Intrastate transportation and storage
- Interstate transportation
- Retail propane

Summary of Operating Financial Performance in fiscal 2007

Our midstream and propane operations are primarily margin-driven businesses, while our transportation and storage operations are primarily fee-driven businesses. Thus, our results are significantly impacted by the margins we realize and the volumes we sell, transport and store, and to a lesser extent, commodity prices. Our fiscal year 2007 results were significantly impacted by our Transwestern acquisition in December 2006 and our Titan acquisition in fiscal year 2006.

The fiscal 2007 year proved to be a challenging year for us. However, despite delays in certain of our major projects and the milder summer months in 2007, particularly in the southern portion of the United States, our management team and assets delivered another strong earnings performance for the year ended August 31, 2007 with $1.7 billion in gross margin and $829.7 million in operating income. In addition to the increased income generated from the Transwestern and Titan acquisitions, we also experienced increased volumes in our natural gas operations and better than expected processing margins throughout the fiscal year. We were also able to withdraw more working natural gas inventories from our Bammel storage facility resulting in increased margins, principally during the three months ended August 31, 2007.

Despite the warmer than normal winter, our propane operations were able to deliver higher than expected results. Our retail volumes increased as a result of acquisitions during fiscal year 2007 and the Titan and other acquisitions during

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fiscal year 2006 which offset the decrease in volumes we experienced due to the warmer weather. We also were able to increase our sales prices which improved our gross margins. Additionally, due to the acquisitions we made during fiscal years 2007 and 2006, our other propane segment revenues, such as appliance sales, labor and tank rentals, also improved over prior years.

We also completed several growth capital projects during the fiscal year ended August 31, 2007 including the Cleburne to Carthage pipeline that extends from Cleburne, Texas to the Carthage Hub in East Texas and the Godley plant. In addition to our internal growth projects we also continued to integrate the Titan operations that were acquired in June 2006 and successfully completed the acquisition of the Transwestern pipeline in a two-step process in December 2006. The Transwestern pipeline is the first FERC-regulated pipeline for the Partnership.

In addition, we continued to secure long-term financing for ETP. We successfully raised $800 million in long-term debt with interest rates ranging from 6.125% to 6.625% and maturities ranging from 10 to 30 years. We also received proceeds of $1.2 billion from the sale of our Common Units during the year ended August 31, 2007. These proceeds were used principally to finance the Transwestern acquisition and to repay indebtedness incurred with the Titan acquisition which closed in June 2006. We also increased our borrowing capacity on our revolving credit facility in June 2007 from $1.5 billion to $2.0 billion (with an option to increase to $3.0 billion). The increased capacity will provide us with the liquidity needed to complete our previously announced expansion projects.

Trends and Outlook

Looking to fiscal 2008, we believe our operations are positioned to provide increasing operating results based on the current levels of contracted and expected capacity to be taken by our customers, our expansion activity completed during fiscal year 2007, additional capacity resulting from pipeline projects expected to be completed within the next twelve to eighteen months (see Item 1 above), and incremental earnings related to the recently acquired Transwestern pipeline. In addition, we recently acquired the Canyon Gathering System in the Uinta-Piceance basins of Utah and Colorado which will provide for continued expansion into natural gas producing regions of the United States.

Analytical Analysis

The following is a discussion of our historical financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included in Item 8 of this Form 10-K.

The comparability of our consolidated financial statements is affected by our 100% acquisition of Transwestern on December 1, 2006 (and our purchase of 50% of CCEH in November 2006), our purchase of Titan in June 2006 and the HPL System in January 2005 and the sale of ETC Oklahoma (Elk City) in April 2005. See Note 2 to our consolidated financial statements for a detailed discussion of our significant acquisitions and dispositions during fiscal years 2007, 2006 and 2005. The comparability is also affected by fluctuation in natural gas prices, mainly in our producer services gas sales and purchases and natural gas sales and purchases on our HPL System. Since we buy and sell natural gas primarily based on either first of month index prices, gas daily average prices or a combination of both, our gas sales and purchases tend to be higher when natural gas prices are high and our gas sales and purchases tend to be lower when natural gas prices are lower. However, a change in natural gas prices is only one of several elements that impact our overall margin. Other factors include, but are not limited to, volumetric changes, our hedging strategies and the use of financial instruments, fee-based revenues, trading activities, and basis differences between market hubs.

The acquisition of Transwestern resulted in a significant increase in our property, plant and equipment, intangible assets and goodwill from August 31, 2006 to August 31, 2007 (see Note 2 to the consolidated financial statements). The increase from August 31, 2006 to August 31, 2007 in our long-term debt was also due to debt issued in connection with and debt assumed in the Transwestern acquisition and approximately $1.0 billion in growth capital expenditures incurred during the year ended August 31, 2007.

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Analysis of Operating Data - Volumes

Midstream

	Years Ended August 31,		
	2007	2006	2005
Natural gas MMBtu/d	941,140	1,552,753	1,578,833
NGLs Bbls/d	25,657	10,425	12,707

For the year ended August 31, 2007, the decrease in natural gas volumes sold was principally due to less favorable market conditions during fiscal 2007 and increased utilization of capacity on our transportation pipelines by third parties resulting in lower sales volumes conducted by our producer services operations. The increase in NGL sales volumes was principally due to the completion of our Godley plant during 2007 and favorable market conditions to process and extract NGLs during fiscal 2007 compared to the same period last year.

For the year ended August 31, 2006, natural gas sales volumes decreased compared to the year ended August 31, 2005 principally due to less marketing activity by our producer services operations towards the latter half of fiscal year 2006 and a change in contract mix with one of our major producers where we now charge a fee to gather, process and transport natural gas rather than buying and selling the natural gas on our behalf. Our NGL sales volumes 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 decrease in NGL sales volumes is principally due to a change in contract mix as noted above and the election to by-pass our processing plant as a result of less favorable market conditions during the second fiscal quarter of the year ended August 31, 2006.

Intrastate Transportation and Storage

	Years Ended August 31,		
	2007	2006	2005
Natural gas MMBtu/d transported	6,124,423	4,633,069	3,495,434
Natural gas MMBtu/d sold	1,400,753	1,580,638	1,361,729

For the year ended August 31, 2007, transported natural gas volumes increased due to our continued efforts to secure more long-term shipper contracts, the completion of the Cleburne to Carthage pipeline, and increased demand to transport gas out of the Barnett Shale and Bossier Sands producing regions. Natural gas sales volumes on the HPL System for the year ended August 31, 2007 decreased principally due to less volumes sold to east Texas markets as a result of lower price differentials and due to the new CenterPoint contract that commenced on April 1, 2007. Under the previous contract, we sold and delivered natural gas to CenterPoint for a bundled price. Under the terms of the new agreement, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas capacity in our Bammel storage facility. As such, we now account for these activities as natural gas transported rather than natural gas sold.

For the year ended August 31, 2006, transported natural gas volumes increased by 1,137,635 MMBtu/d. The increase in transportation volumes is principally due to the increased volumes experienced in the Oasis pipeline, ET Fuel System and East Texas pipeline as a result of our effort to secure firm commitments on our transportation assets and a higher price differential between the Waha and Katy market hubs during the periods presented. Additionally, warmer weather during the 2006 fiscal year resulted in an increase in demand for natural gas. The higher temperatures required more demand for natural gas to be used by electricity-producing power plants connected to our assets. Natural gas sales volumes on the HPL System for the year ended August 31, 2006 increased 218,909 MMBtu/d compared to the year ended August 31, 2005, principally due to increased marketing efforts with our existing and new customers and increased well connects which has increased our supply on the HPL System.

Interstate Transportation

	Years Ended August 31,		
	2007	2006	2005
Natural gas MMBtu/d transported	1,802,109		
Natural gas MMBtu/d sold	19,680		

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The increase was due to the 100% acquisition of Transwestern on December 1, 2006.

Retail Propane

	Years Ended August 31,		
	2007	2006	2005
Retail propane gallons sold (in thousands)	604,269	429,118	406,334

The retail propane operations realized significant increases in gallons sold in the year ended August 31, 2007 as compared to the year ended August 31, 2006 (a 175.2 million net gallon increase) primarily due to the Titan acquisition in June 2006. The combination of below normal degree days, customer conservation, and the slow down of new home construction in our propane markets has contributed to a decrease in expected volumes sold and slowed internal growth. The overall weather in our areas of operations during the year ended August 31, 2007 was 10.6% warmer than the year ended August 31, 2006 and 7.2% warmer than normal.

The 22.8 million net gallon increase in retail propane gallons sold for the year ended August 31, 2006, compared to the year ended August 31, 2005, includes a 24.5 million gallon increase due to the Titan acquisition for the months of June, July and August 2006, 15.9 million gallons were added through other propane acquisitions, offset by a decrease of 17.6 million gallons related to warm weather and higher propane commodity prices. The weather in our areas of operations during the year ended August 31, 2006 was 3.5% warmer than the year ended August 31, 2005 and 10.6% warmer than normal.

Analysis of Results of Operations

In the following analysis of results of operations, tabular dollar amounts are expressed in thousands.

Consolidated Results

	Years Ended August 31,			Amount of Change	
	2007	2006	2005	2007-2006	2006-2005
Revenues	$ 6,792,037	$ 7,859,096	$ 6,168,798	$ (1,067,059)	$ 1,690,298
Cost of sales	5,078,206	6,568,316	5,381,515	(1,490,110)	1,186,801
Gross margin	1,713,831	1,290,780	787,283	423,051	503,497
Operating expenses	559,600	422,989	319,554	136,611	103,435
Selling, general and administrative	145,417	107,505	62,735	37,912	44,770
Depreciation and amortization	179,162	117,415	92,943	61,747	24,472
Operating income	829,652	642,871	312,051	186,781	330,820
Interest expense	(175,563)	(113,857)	(93,017)	(61,706)	(20,840)
Loss on extinguishment of debt			(9,550)		9,550
Equity in earnings (losses) of affiliates	5,161	(479)	(376)	5,640	(103)
Gain (loss) on disposal of assets	(6,310)	851	(330)	(7,161)	1,181
Interest and other income, net	37,999	14,620	631	23,379	13,989
Income tax expense	(13,658)	(25,920)	(7,295)	12,262	(18,625)
Minority interests	(1,142)	(2,234)	(731)	1,092	(1,503)
Income from continuing operations	676,139	515,852	201,383	160,287	314,469
Income from discontinued operations, net of income tax expense			147,967		(147,967)

Net income	$ 676,139	$ 515,852	$ 349,350	$ 160,287	$ 166,502

See the detailed discussion of revenues, costs of sales, gross margin and operating expense by operating segment below.

Interest Expense. For the year ended August 31, 2007 compared to the year ended August 31, 2006, interest expense increased $61.7 million. The principal factor for this increase is a net $51.2 million increase in interest expense related to borrowings on the Partnership s 2006 and 2005 Senior Notes and the revolving credit facility. Borrowings increased primarily due to the financing of our growth capital expenditures and the CCEH/Transwestern and Titan acquisitions. Debt assumed in the Transwestern acquisition resulted in $12.5 million of increased interest expense. During the year ended August 31, 2006 gains of $0.3 million on interest rate swaps were recorded as a reduction to interest expense. Such gains were not recognized in interest expense in the year ended August 31, 2007; rather, such gains are included in interest and other income. Hedge ineffectiveness charges increased interest expense by $1.8 million in fiscal 2007, compared to gains of $0.8 million in fiscal 2006. See Note 10 Price Risk Management Assets and Liabilities , included in our consolidated financial statements for further discussion on interest rate hedges. Propane related interest decreased $5.1 million due primarily to the scheduled debt payments that have occurred between fiscal periods 2006 and 2007.

For the year ended August 31, 2006 compared to the year ended August 31, 2005, interest expense increased $20.8 million. The principal factor for this increase is a net $22.1 million increase in interest expense related to borrowings on the 2005 Senior Notes and the revolving credit facility which we entered into January 2005 to refinance debt at ETC OLP and fund the HPL System acquisition, offset principally by an increase in unrealized gains and the ineffective charges of $1.2 million related to interest rate swaps. See Note 10 Price Risk Management Assets and Liabilities , included in our consolidated financial statements for further discussion on interest rate hedges.

Loss on Extinguishment of Debt. During the year ended August 31, 2005, we wrote off $9.6 million of debt issuance costs associated with the debt that was repaid with the proceeds from the issuance of $750.0 million of 5.95% senior notes.

Equity in Earnings of Affiliates. The increase in equity in earnings of affiliates for the year ended August 31, 2007 compared to the year ended August 31, 2006 was due primarily to $5.1 million of equity income from our 50% ownership of CCEH for the month of November 2006. We did not have an investment in CCEH in fiscal 2006. We redeemed our investment in CCEH in connection with our Transwestern acquisition on December 1, 2006.

Gain (Loss) on Disposal of Assets. The loss on disposal of assets reflected in the year ended August 31, 2007 was principally due to losses resulting from the sale of a compressor station.

Interest and Other Income, Net. The increase in interest and other income, net of $23.4 million for the year ended August 31, 2007 compared to the year ended August 31, 2006, is due primarily to gains on interest rate swaps that are not accounted for as cash flow hedges. Such gains were included in interest expense in fiscal 2006. Other income in fiscal year 2006 includes $7.7 million received from the favorable judgment on the SCANA litigation (see Notes 6 and 9 of our consolidated financial statements for further detail).

The increase in interest and other income, net of $14.0 million for the year ended August 31, 2006 compared to the year ended August 31, 2005, is due primarily to $7.7 million received from the favorable judgment on the SCANA litigation (see Notes 6 and 9 of our consolidated financial statements for further detail).

Income Tax Expense. As a partnership, we are not subject to income taxes. However, certain wholly-owned subsidiaries are corporations that are subject to income taxes.

The decreased expense for the year ended August 31, 2007 was attributed principally to higher income from trading gains recognized by a taxable subsidiary during the year ended August 31, 2006, than was realized by such subsidiary in the current fiscal year. The decrease was partially offset by the Texas margin tax that was not effective until January 1, 2007.

The increased expense of $18.6 million for the year ended August 31, 2006 is attributed principally to higher income due to gains on financial derivative activity recognized by a taxable subsidiary. No similar gains were realized by such subsidiary in prior periods.

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 the year ended August 31, 2005, the income from discontinued operations included the gain on sale of the Elk City System of $142.5 million, net of income taxes, and revenues of $105.5 million offset by costs and expenses of $100.0 million, resulting in income from discontinued operations of $148.0 million.

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There were no discontinued operations for the years ended August 31, 2006 or 2007.

Segment Operating Results

We evaluate segment performance based on operating income (either in total or by individual segment) which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments.

We do not include earnings from equity method unconsolidated affiliates in our measurement of operating income because such earnings have not been significant historically.

For additional information regarding our business segments, see Item 1 and Notes 1 and 14 to our consolidated financial statements included under Item 8 of this annual report.

Operating income by segment is as follows:

	Years Ended August 31,			Amount of Change	
	2007	**2006**	**2005**	**2007-2006**	**2006-2005**
Midstream	$ 123,176	$ 151,507	$ 99,133	$ (28,331)	$ 52,374
Intrastate Transportation and Storage	488,098	430,698	160,098	57,400	270,600
Interstate Transportation	95,650			95,650	
Retail Propane	124,263	76,055	66,902	48,208	9,153
Other	1,735	1,899	(683)	(164)	2,582
Unallocated selling, general and administrative expenses	(3,270)	(17,288)	(13,399)	14,018	(3,889)
Operating income	$ 829,652	$ 642,871	$ 312,051	$ 186,781	$ 330,820

We do not believe the Other operating income is material for further disclosure and/or discussion.

Unallocated Selling, General and Administrative Expenses. Prior to December 2006, the selling, general and administrative expenses that relate to the general operations of the Partnership were not allocated to our segments. In conjunction with the Transwestern acquisition, selling, general and administrative expenses are now allocated to the Operating Partnerships. For the year ended August 31, 2007, a net $18.4 million was allocated to the Operating Partnerships, which constituted the decrease in total unallocated selling general and administrative expenses from the year ended August 31, 2006. The decrease in the unallocated selling, general and administrative expenses due to the allocations now in place to the Operating Partnerships, is offset by increases in expenses primarily related to management incentive plans.

Unallocated selling, general and administrative expenses increased $3.9 million for the year ended August 31, 2006 compared to the year ended August 31, 2005. This increase is primarily attributed to a $1.0 million increase in executive salaries due to additional staffing, a $0.4 million increase in professional fees due to our on-going efforts related to the Sarbanes-Oxley Act and other Partnership expenses, and a $2.5 million increase in additional executive bonuses and non-cash compensation related to additional staffing and outstanding restricted units awards.

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Midstream

	Years Ended August 31, 2007	2006	2005	Amount of Change 2007-2006	2006-2005
Revenues	$ 2,853,496	$ 4,223,544	$ 3,246,772	$ (1,370,048)	$ 976,772
Cost of sales	2,632,187	4,000,461	3,102,539	(1,368,274)	897,922
Gross margin	221,309	223,083	144,233	(1,774)	78,850
Operating expenses	39,148	31,910	22,835	7,238	9,075
Selling, general and administrative	35,597	23,922	9,685	11,675	14,237
Depreciation and amortization	23,388	15,744	12,580	7,644	3,164
Segment operating income	$ 123,176	$ 151,507	$ 99,133	$ (28,331)	$ 52,374

Gross Margin. For the year ended August 31, 2007, midstream s gross margin decreased by $1.8 million primarily due to the net effect of the following factors:

Decrease in net trading revenues of $17.9 million. During the fiscal 2006 period, we recognized trading gains resulting principally from commodities futures positions that benefited from market anomalies following the hurricanes that struck the Texas and Louisiana coasts in August and September 2005. Trading activities during the year ended August 31, 2007 resulted in a net gain of $2.2 million;

Decrease in non-trading margin from our marketing activities of $36.0 million. Market conditions, including lower basis differentials between the west and east Texas markets and increased third-party utilization of our transportation pipeline capacity, resulted in lower sales volumes conducted by our producer services operations; and

Increase in processing margin and fee-based revenue. The increase was due to the completion of our Godley plant in the first quarter of 2007, the acquisition of three gathering systems during fiscal 2007, and favorable processing conditions during fiscal 2007 compared to the same period last year at our Southeast Texas System.

For the year ended August 31, 2006, midstream s gross margin increased by $78.9 million primarily due to the following factors:

Trading gains recognized during the 2006 fiscal year resulting from commodities futures positions that benefited from market anomalies following the hurricanes that struck the Texas and Louisiana coasts in August and September 2005; and

Increased processing margins on our Southeast Texas System as a result of favorable processing conditions during the year ended August 31, 2006 compared to the year ended August 31, 2005.

Operating Expenses. Midstream operating expenses increased $7.2 million for the year ended August 31, 2007 compared to the year ended August 31, 2006. The increase was primarily driven by increased compressor rental expense of $3.7 million, increased compressor maintenance of $1.0 million, increased electricity costs of $0.9 million, and increased employee-related costs, such as salaries, incentive compensation and healthcare costs, of $1.8 million. The increases were primarily driven by the Godley plant addition and the acquisition of three gathering systems during the first six months of fiscal 2007. The increases were offset by reduced measurement expense of $1.6 million due to a larger portion being allocated to the transportation segment due to the continued expansion in that segment.

Midstream operating expenses increased $9.1 million between the years ended August 31, 2006 and 2005 and was primarily driven by $3.2 million in increased measurement expenses, $1.1 million in increased chemical costs, $0.7 million in scheduled compressor and pipeline maintenance expense and pipeline integrity costs, $0.9 million in employee costs, and increases of $3.2 million in other operating expenses.

Selling, General and Administrative Expenses. Midstream general and administrative expenses for the year ended August 31, 2007 increased $11.7 million compared to the year ended August 31, 2006. The increase was attributable to $13.2 million of increased legal costs primarily associated with regulatory inquiries, a $4.1 million allocation of parent company administrative expenses for overhead costs which previously had not been allocated, and increases of $3.9 million in employee-related costs such as salaries, incentive compensation and healthcare costs. The increase was offset by increases of $7.9 million in departmental costs allocated to the intrastate transportation and storage operating segment and an increase of $2.4 million in overhead costs capitalized to capital expansion projects.

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Midstream selling, general and administrative expenses for the year ended August 31, 2006 increased $14.2 million compared to the year ended August 31, 2005. The increase was attributable to increases of $28.5 million in employee-related costs such as salaries, incentive compensation and healthcare costs, insurance premium increases of $2.2 million, increases in office-related expenses of $4.0 million, $2.7 million in increased legal, audit and consulting fees, and increases in other general and administrative expenses of $2.0 million. The increase was offset by increases of $25.2 million in departmental costs allocated to the intrastate transportation and storage operating segment. The increased costs are principally due to the growth caused by the recent acquisitions, internal growth projects and upgraded information systems.

Depreciation and Amortization. The increase of $7.6 million for the year ended August 31, 2007 compared to the year ended August 31, 2006 is principally due to plant and equipment placed into service during fiscal year 2007, the completion of our Godley plant in the first fiscal quarter of 2007, and the acquisitions of three gathering systems in the first and second fiscal quarters of 2007.

Midstream depreciation and amortization expense increased $3.2 million for the year ended August 31, 2006 compared to fiscal year 2005 principally due to the Devon acquisition in November 2004 and pipeline and equipment placed into service subsequent to August 31, 2005.

Intrastate Transportation and Storage

	Years Ended August 31,			Amount of Change	
	2007	**2006**	**2005**	**2007-2006**	**2006-2005**
Revenues	$ 3,915,932	$ 5,013,224	$ 2,608,108	$ (1,097,292)	$ 2,405,116
Cost of sales	3,137,712	4,322,217	2,280,082	(1,184,505)	2,042,135
Gross margin	778,220	691,007	328,026	87,213	362,981
Operating expenses	181,133	171,312	113,166	9,821	58,146
Selling, general and administrative	52,844	46,520	27,020	6,324	19,500
Depreciation and amortization	56,145	42,477	27,742	13,668	14,735
Segment operating income	$ 488,098	$ 430,698	$ 160,098	$ 57,400	$ 270,600

Gross Margin. For the year ended August 31, 2007 as compared to the year ended August 31, 2006, intrastate transportation and storage gross margin increased by $87.2 million, principally due to the net effect of the following:

- Volumes. Overall volumes on our transportation pipelines were higher during fiscal 2007 compared to fiscal 2006 due to the completion of the Cleburne to Carthage pipeline, continued efforts to secure long-term shipper contracts, increased demand to transport natural gas from the Barnett Shale and Bossier Sands producing regions, and a colder winter in fiscal 2007. Transportation fees increased approximately $61.0 million for the year ended August 31, 2007 compared to the year ended August 31, 2006. Retention revenue increased approximately $35.1 million due to increased volumes transported on our pipelines;

- Lower natural gas prices. Excluding the impact of volumetric changes, our fuel retention fees are directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and decreases in natural gas prices tend to decrease our fuel retention fees. Our average natural gas prices for retained fuel decreased from a range of $5.00 to $12.00/MMBtu during the year ended August 31, 2006 to $4.00 to $7.00/MMBtu during the same period this year resulting in a decrease in revenue by $28.8 million;

- Increase in storage margin of $26.0 million. The increase was due to approximately $40.0 million in margin recognized on 17.5 Bcf more volume withdrawn from our Bammel storage facility in fiscal 2007 than in fiscal 2006 and a significant loss on settled derivatives during fiscal 2006. These increases were offset by approximately $18.0 million in margin on gas sold from our Bammel storage facility and delivered to a customer in September 2005. There were no similar sales during the year ended August 31, 2007; and

Decrease in margin of $28.7 million related to well head volumes. As discussed above, we purchase natural gas from producers at a discount to a specified price and resell to customers at an index price. We experienced lower volumes and lower natural gas prices during the year ended August 31, 2007 compared to the same period last year.

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For the year ended August 31, 2006 as compared to fiscal year 2005, intrastate transportation and storage gross margin increased by $363.0 million, principally due to the following:

- Increased volumes and prices. 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 on our transportation pipeline systems. The price differential between the Waha and Katy market hubs increased between the 2005 and 2006 fiscal years, thereby influencing shippers to transport natural gas to regions where natural gas prices are more favorable. We have successfully secured more firm contracts as evidenced by our transportation agreement with XTO (see Note 9 to our consolidated financial statements). In addition, our Fort Worth Basin expansion, completed in May 2005, allowed shippers to move more gas from the Barnett Shale. Our margins for the year ended August 31, 2006 were also affected favorably by higher than normal temperatures during the year ended August 31, 2006 in regions where our assets are located. The higher temperatures increased demand for natural gas to be used by electricity-producing power plants connected to these assets. Furthermore, our margin was favorably impacted by an increase in fuel retention fees due to the increase in volumes on our transportation pipelines and an increase in average natural gas prices during the 2006 fiscal year compared to the 2005 fiscal year. Excluding the impact of volumetric changes, our fuel retention fees are directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and decreases in natural gas prices tend to decrease our fuel retention fees;

- The acquisition of the HPL System in January 2005. The results for the year ended August 31, 2005 contain seven months of the HPL System s operating results as compared to the HPL System twelve months of operating results included in fiscal year 2006. For the year ended August 31, 2006, the HPL System margin was principally affected by the sale of natural gas held in storage during the winter months when demand for natural gas is strong, increased margins resulting from favorable pricing between the west and east markets in the Houston Ship Channel, and hedging gains as noted below. The favorable pricing was attributed to the effects of the hurricanes that struck the east Texas and Louisiana coastlines in August and September 2005; and

- Discontinued Hedge Accounting. In January and February 2006, we discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified for and designated as cash flow hedges related to forecasted sales of natural gas stored in our Bammel storage facilities. The discontinuation resulted from our determination that the originally forecasted sales of natural gas from the storage facilities were no longer probable to occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. The determination was made principally due to the unseasonably warm weather that occurred during January 2006 through March 2006. As a result, during the year ended August 31, 2006, we recognized previously deferred unrealized gains of approximately $84.7 million from the discontinuation of hedge accounting.

Operating Expenses. Intrastate transportation and storage operating expenses increased $9.8 million when comparing the year ended August 31, 2007 to the year ended August 31, 2006. The increase was principally attributable to increases of $12.5 million in pipeline and compressor maintenance and compressor rentals, $3.6 million in property taxes, and $2.3 million in employee-related costs such as salaries, incentive compensation and healthcare costs. These increases were offset by a decrease of $11.0 million in fuel consumption which was due to higher natural gas prices in the early part of fiscal 2006.

For the year ended August 31, 2006 compared to fiscal year 2005, intrastate transportation and storage operating expenses increased $58.1 million. The increase was principally attributable to increases of $32.4 million in operating expenses related to the HPL System acquisition, $19.5 million related to compressor fuel consumption resulting from higher throughput volumes and increased gas prices during the year ended August 31, 2006, $2.1 million in property taxes, $2.5 million in pipeline maintenance, $1.4 million in compressor rental and maintenance, and $1.3 million in increased employee costs, offset by a decrease of $1.1 million in other operating expenses.

Selling, General and Administrative Expenses. Intrastate transportation and storage general and administrative expenses increased $6.3 million for the year ended August 31, 2007 compared to the year ended August 31, 2006 principally due to an increase in certain departmental costs allocated from the midstream segment. The increase in allocated departmental costs is primarily due to the significance of the operations added to the intrastate transportation segment from the various construction projects.

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For the year ended August 31, 2006 compared to the year ended August 31, 2005, intrastate transportation and storage selling, general and administrative expenses increased $19.5 million principally due to an increase in certain departmental costs allocated from the midstream segment. The increase in allocated departmental costs is due to the increase in employee headcount resulting primarily from the HPL System acquisition and an increase in salaries and wages, incentive compensation expense, and other employee-related expenses.

Depreciation and amortization. Intrastate transportation and storage depreciation and amortization expense increased $13.7 million for the year ended August 31, 2007 compared to the year ended August 31, 2006, principally due to plant and equipment placed into service during fiscal year 2007.

For the year ended August 31, 2006 compared to the year ended August 31, 2005, intrastate transportation and storage depreciation and amortization expense increased $14.7 million, principally due to the HPL System acquisition in January 2005, the Fort Worth Basin Pipeline completed in May 2005 and additional compressors and equipment added to existing systems.

Interstate Transportation

	Years Ended August 31,		Amount of
	2007	2006	Change
Revenues	$ 178,663	$	$ 178,663
Operating expenses	36,295		36,295
Selling, general and administrative	18,746		18,746
Depreciation and amortization	27,972		27,972
Segment operating income	$ 95,650	$	$ 95,650

The increase in all categories between fiscal years ending August 31, 2007 and 2006 was due to the acquisition of 100% of Transwestern on December 1, 2006.

No comparative data is presented for fiscal year 2005 as the Transwestern acquisition did not take place until fiscal year 2007.

Retail Propane

	Years Ended August 31,			Amount of Change	
	2007	2006	2005	2007-2006	2006-2005
Retail propane revenues	$ 1,179,073	$ 799,358	$ 641,071	$ 379,715	$ 158,287
Other retail propane related revenues	105,794	80,198	68,402	25,596	11,796
Retail propane cost of sales	734,204	493,642	384,186	240,562	109,456
Other retail propane related cost of sales	25,430	21,776	19,554	3,654	2,222
Gross margin	525,233	364,138	305,733	161,095	58,405
Operating expenses	297,469	212,188	176,277	85,281	35,911
Selling, general and administrative	32,668	17,859	11,067	14,809	6,792
Depreciation and amortization	70,833	58,036	51,487	12,797	6,549
Segment operating income	$ 124,263	$ 76,055	$ 66,902	$ 48,208	$ 9,153

Revenues. Retail propane revenue increased $379.7 million between the years ended August 31, 2007 and 2006, mainly due to the increase in volumes sold by customer service locations added through the Titan acquisition in June 2006. The increase in retail propane revenues was offset somewhat by weather that was 7.2% warmer than normal weather and 10.6% warmer than last year. Other retail propane related revenues increased $25.6 million for the year ended August 31, 2007 compared to fiscal year 2006 primarily due to other propane related revenues of companies we have acquired between the two years and enhanced fee generating programs in servicing our customers.

Of the total increase in retail propane revenue of $158.3 million between the years ended August 31, 2006 and 2005, $47.1 million is due to the increase in volumes sold by customer service locations added through the Titan acquisition in

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June 2006, $29.6 million is due to the increase in volumes sold by customer service locations added through other propane acquisitions and $114.4 million is due to higher selling prices. These increases were offset by a decrease of $32.8 million due to the adverse impact of weather related volumes described above. Other propane related revenues increased $11.8 million for the year ended August 31, 2006 compared to fiscal year 2005 primarily due to other propane related revenues of companies we have acquired between the two years.

Costs of Sales. During the year ended August 31, 2007 compared to the year ended August 31, 2006, retail propane cost of sales increased by $240.6 million which mainly relates to the increase in gallons sold by customer service locations added through the Titan acquisition.

During the year ended August 31, 2006 compared to the year ended August 31, 2005, retail propane cost of sales increased by $109.5 million of which $30.8 million is a result of an overall increase in gallons sold by customer service locations added through the Titan acquisition, $18.2 million due to an overall increase in gallons sold by customer service locations added through other propane acquisitions and $80.7 million is due to higher cost of fuel, offset by a decrease of $20.2 million due to the impact of weather related volumes described above.

Gross Margin. The overall increase in gross margins for the year ended August 31, 2007 compared to fiscal year 2006 is primarily related to the Titan acquisition in June 2006. The propane margin remained strong during the fiscal year ended August 31, 2007 during the periods of warmer weather and higher fuel prices. Optimization of the margins is influenced by market opportunities, independent competitors and concerns for long term retention of customers.

The overall increase in gross margins for the year ended August 31, 2006 compared to fiscal year 2005 is a function of acquisition-related increases and higher sales prices.

Operating Expenses. During the year ended August 31, 2007, operating expenses increased by $85.3 million compared to the same period last year. The increase is directly related to the operating expenses of the identifiable Titan operations. Included in these operating expenses are increases that relate to higher vehicle fuel costs and other vehicle expenses, and general increases in other operating expenses including safety training costs of the newly acquired employees from the Titan acquisition, and other acquisition costs related to blends and mergers of propane locations to gain forward synergies and cost savings.

During the year ended August 31, 2006, operating expenses increased by $35.9 million compared to fiscal 2005 due to a combination of a $21.4 million increase due to the Titan acquisition, a $9.2 million increase in our employee base from other acquisitions and annual salary increases, $3.4 million due to higher fuel costs to run our vehicles and other vehicle expenses, and a $4.7 million general increase in other operating expenses primarily from other acquisitions, offset by a $2.8 million net decrease in other operating expenses.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses for the comparable years of August 31, 2007 and 2006 is primarily due to increases from administrative expense allocations, increases in administrative bonuses, salaries and deferred compensation expense related to increases in staffing and additional restricted unit awards outstanding and the addition of administrative employees from the Titan acquisition. The increase also includes increases in our IT costs as we continue to enhance our current infrastructure for our administrative and propane systems. Effective with the Transwestern acquisition in December 2006, an allocation of administrative expenses is now made to the operating partnerships, which increased the retail propane selling, general and administrative expenses by a net $7.9 million for the year ended August 31, 2007.

The increase in selling, general and administrative expenses for the comparable years of August 31, 2006 and 2005 is primarily due to increases in administrative bonuses, salaries and deferred compensation expense related to increases in staffing and additional restricted unit awards outstanding.

Depreciation and Amortization Expense. The increase of $12.8 million in depreciation and amortization expense for the year ended August 31, 2007 as compared to 2006 is due primarily to the acquisition of Titan on June 1, 2006. Depreciation and amortization increased $6.5 million for the fiscal year ended August 31, 2006 as compared to August 31, 2005, primarily due to the depreciation and amortization of assets and amortizable intangibles added through acquisitions during fiscal 2006.

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Income Taxes

As a limited partnership we generally are not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended August 31, 2007, 2006 and 2005, our non-qualifying income was not expected to, or did not, exceed the statutory limit.

Our partnership will be considered to have terminated for federal income tax purposes if transfers of units within a 12-month period constitute the sale or exchange of 50% or more of our capital and profit interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of our capital and profits interests within the prior 12-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

Based on the information currently available to us, we believe that we exceeded the 50% threshold on May 7, 2007, and, as a result, we have determined that our partnership has terminated for federal tax income purposes on that date. This termination does not affect our classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income for federal income tax purposes. This termination will require us to close our taxable year, make new elections as to various tax matters and reset the depreciation schedule for our depreciable assets for federal income tax purposes. The resetting of our depreciation schedule will result in a deferral of the depreciation deductions allowable in computing the taxable income allocated to our Unitholders. However, certain elections we will make in connection with this tax termination will allow us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of our Unitholders, which deductions had not previously been utilized in computing taxable income allocable to our Unitholders. As a consequence of these factors, we currently estimate, based on our current distribution levels and various assumptions regarding our gross income and capital expenditures during these respective periods, that a recent purchaser of units would be allocated taxable income of between 10% and 20% of the cash expected to be distributed to such Unitholder for the 2007 calendar year and less than 10% of the cash expected to be distributed to such Unitholder for the 2008 calendar year. We estimate, based on the same assumptions, that a Unitholder who purchased units prior to our combination with Heritage Propane, L.P. in January 2004 would be allocated taxable income of approximately 90% of the cash distributed to him for the 2007 calendar year and approximately 50% of the cash distributed to him for the 2008 calendar year. Beginning in 2008, we estimate, based on the same assumptions, that a new purchaser of our units, and current Unitholders who purchased our units more recently, would be allocated taxable income of less than 10% of the cash distributed to them for the 2008 calendar year. In the case of a Unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our income or loss being includable in their taxable income for the year of termination.

As a result of the tax termination discussed above, we elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our subsidiary, HHI, which owns our Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of our common units. The amount of such goodwill accumulated as of the date of our acquisition of HHI (approximately $158 million) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. We account for HHI using the treasury stock method due to its ownership of our Class E units. Due to the accounting rules outlined in SFAS 109 and related Interpretations, we account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of our HHI purchase price allocation, which effectively results in a charge to our common equity and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the year ended August 31, 2007, this resulted in a current tax expense and deferred tax benefit (with a corresponding charge to common equity as an adjustment of the purchase price allocation) of approximately $1.2 million. As of August 31, 2007, the amount of tax goodwill to be amortized over the next 15 years for which HHI will receive a remedial income allocation is approximately $155 million.

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The difference between the statutory rate and the effective rate is summarized as follows:

	Years Ended August 31, 2007	2006	2005
Federal statutory tax rate	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	1.25%	3.10%	3.56%
Earnings not subject to tax at the Partnership level	(34.25)%	(33.30)%	(36.01)%
Effective tax rate	2.00%	4.80%	2.55%

Income tax expense consists of the following current and deferred amounts:

	Years Ended August 31, 2007	2006	2005
Continuing operations -			
Current provision:			
Federal	$ 7,896	$ 27,640	$ 5,043
State	9,803	1,994	963
Total	17,699	29,634	6,006
Deferred provision:			
Federal	(4,598)	(3,329)	882
State	557	(385)	407
Total	(4,041)	(3,714)	1,289
Total tax provision on continuing operations	13,658	25,920	7,295
Discontinued operations -			
Current income tax expense:			
Federal			1,570
State			259
Total tax provision on discontinued operations			1,829
Total Tax Provision	$ 13,658	$ 25,920	$ 9,124

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $6.9 million. There is no comparable state tax expense for the years ended August 31, 2006 or 2005.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our partners 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 approximately $70 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 approximately $35 million in the next fiscal year;

- growth capital expenditures, mainly for constructing new pipelines, processing plants, treating plants and compression for the midstream and intrastate transportation and storage segment for which we expect to expend approximately $1.0 billion in the next fiscal year. We also expect to spend approximately $800 million in our interstate segment for constructing new pipelines and pipeline expansion and approximately $30 million for customer propane tanks in the next fiscal year; and

- acquisition capital expenditures including acquisition of new pipeline systems and propane operations. As a partnership practice, we do not budget for acquisitions.

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

- growth capital expenditures may be financed by the proceeds of borrowings under the existing credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof; and

- acquisition capital expenditures may 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 used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures other than those expenditures necessary to maintain the service capacity of our existing assets. 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 businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors into our anticipated growth capital expenditures for each fiscal year.

We manage our exposure to increased pipe costs by purchasing steel and reserving mill space, as projects are approved, in advance of construction. However, there is no assurance that we will not be impacted by increased pipe costs and limited mill space.

In connection with the HPL System acquisition, we 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.

During our fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1.0 billion aggregate offering price of Common Units. Through August 31, 2007, we have not made any sales under this Registration Statement.

Cash Flows

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 Transwestern and Titan operations, and other factors.

Operating Activities. Cash provided by operating activities during the year ended August 31, 2007, was $1.1 billion as compared to cash provided by operating activities of $543.9 million for the year ended August 31, 2006. The net cash provided by operations for the year ended

August 31, 2007 consisted of net income of $676.1 million, non-cash charges of $195.4 million, principally depreciation and amortization, unit based compensation expense, and deferred taxes, and cash from changes in operating assets and liabilities of $241.1 million. Various components of operating assets and liabilities changed significantly from the prior period due to factors such as the change in value of price risk management assets and liabilities, variance in the timing of accounts receivable collections, payments on accounts payable, and the timing of the purchase and sale of inventories related to the propane and intrastate transportation and storage operations.

Investing Activities. Cash used in investing activities during the year ended August 31, 2007 of $2.2 billion is comprised primarily of cash paid for our investment in CCEH of $1.0 billion (net of the receipt of $49.0 million from CCEH as per the terms of our acquisition agreement), other acquisitions of $90.7 million and $1.0 billion invested for growth capital expenditures (including the payment of $9.4 million accrued in prior periods) of which $974.6 million related to natural gas operations and $32.9 million to propane operations. We also incurred $89.2 million in maintenance expenditures needed to sustain operations of which $63.2 million related to natural gas operations and $26.0 million to propane.

Financing Activities. Cash provided by financing activities was $1.1 billion for the year ended August 31, 2007. We received $1.2 billion in proceeds from the sale of Class G Units to ETE and our General Partner contributed $24.5 million to maintain its two percent ownership in us. We used $1.0 billion of the proceeds to fund the purchase of the member interests of CCEH and the remainder was used to repay the indebtedness we incurred in connection with the Titan acquisition as discussed in Note 2 to our consolidated financial statements. On October 23, 2006, we received net proceeds of $791.0 million from the issuance of senior notes (see Note 5 to our consolidated financial statements) which we used to repay borrowings under the Partnership s revolving credit facility. In January and February 2007, we borrowed a total of approximately $307.0 million on our Revolving Credit Facility to fund required pre-payments of the debt we assumed in connection with our acquisition of Transwestern. In May 2007, Transwestern issued $307.0 million principal of Senior Unsecured Series Notes from which we used $295.0 million to repay borrowings and accrued interest outstanding under the Partnership s revolving credit facility and $12.0 million for general partnership purposes. During the year ended August 31, 2007, we paid distributions of $622.5 million to our partners.

Financing and Sources of Liquidity

Description of Indebtedness

Our indebtedness as of August 31, 2007 consists of $750 million in principal amount of 5.95% Senior Notes due 2015, $400 million in principal amount of 5.65% Senior Notes due 2012, $400 million in principal amount of 6.125% Senior Notes due 2017 and $400 million in principal amount of 6.625% Senior Notes due 2036 (collectively, the ETP Senior Notes), a revolving credit facility that allows for borrowings of up to $2.0 billion (expandable to $3.0 billion) available through June 20, 2012 (the ETP Credit Facility), and a $310 million, 364-day term loan credit facility executed on October 5, 2007 (discussed below). We also currently maintain separate credit facilities for Transwestern and HOLP. The terms of our indebtedness and our Operating Partnerships are described in more detail below and in Note 5 to our consolidated financial statements. Failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability of 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, 2007, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

ETP Senior Notes

On October 23, 2006, we closed the issuance, under our $1.5 billion S-3 registration statement, of $400 million of 6.125% senior notes due 2017 and $400 million of 6.625% senior notes due 2036. We used the net proceeds of approximately $791 million from the issuance of the notes to repay borrowings and accrued interest under our previously existing revolving credit facility, to pay expenses associated with the offering and for general partnership purposes. Interest on the 2017 senior notes is payable semiannually on February 15 and August 15 of each year, beginning February 15, 2007, and interest on the 2036 senior notes is payable semiannually on April 15 and October 15 of each year, beginning April 15, 2007. The notes are unsecured senior obligations of the Partnership.

The ETP Senior Notes represent our senior unsecured obligations and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. In connection with the Partnership entering into the credit agreement for the ETP Credit Facility in July 2007 as described in more detail below, all guarantees by ETC OLP, Titan and all of their direct and indirect wholly-owned subsidiaries for the ETP Senior Notes were released and discharged. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

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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.

Transwestern Assumed Long-Term Debt and Senior Unsecured Series Notes

On December 1, 2006 we assumed the following long-term debt in connection with the Transwestern acquisition:

5.39% Notes due November 17, 2014	$ 270,000
5.54% Notes due November 17, 2016	250,000
Total long-term debt outstanding	520,000
Unamortized debt discount	(623)
Total long-term debt assumed	$ 519,377

No principal payments are required under any of the Transwestern debt agreements prior to their respective maturity dates. Due to a change in control provision in Transwestern s debt agreements, Transwestern was required to pre-pay $292 million and $15 million in February and March 2007, respectively. These payments were financed with borrowings from the ETP s previously existing revolving credit facility.

In May 2007, Transwestern issued a total of $307 million aggregate principal amount of Senior Unsecured Series Notes (Transwestern Series Notes) comprised of the following:

Principal	Interest Rate	Maturity Date
$ 82,000	5.64%	May 24, 2017
150,000	5.89%	May 24, 2022
75,000	6.16%	May 24, 2037

The Partnership used $295 million of the proceeds received to repay borrowings and accrued interest outstanding under its then existing revolving credit facility and $12 million for general partnership purposes. Interest is payable semi-annually, and the Transwestern Series Notes rank pari passu with Transwestern s other unsecured debt. The Transwestern Series Notes are prepayable at any time in whole or pro rata in part, subject to a premium or upon a change of control event, as defined.

Transwestern s credit agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and require certain debt to capitalization ratios.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes. In addition to the stated interest rate for the HOLP Notes, we are required to pay an additional 1% per annum on the outstanding balance of the HOLP Notes at such time as the HOLP Notes are not rated investment grade status or higher. As of August 31, 2007 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

Revolving Credit and Short-Term Debt Facilities

ETP Facilities

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ETP Credit Facility. On July 20, 2007, we entered into the ETP Credit Facility with Wachovia Bank, National Association, as administrative agent and Bank of America, N.A., as syndication agent, and certain other agents and lenders. The ETP Credit Facility replaced our previously existing $1.5 billion revolving credit facility, and all outstanding borrowings and letters of credit under our previously existing credit facility were replaced by borrowings and letters of credit under the ETP Credit Facility. The $1.5 billion prior credit facility was then terminated. The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion at our option (subject to the approval of the administrative agent under the Amended and Restated Credit Agreement, which approval is not to be unreasonably withheld). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments under the ETP Credit Facility). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The ETP Credit Facility has a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2.0 billion unless expanded to $3.0 billion) less the sum of all outstanding revolving credit loans and the letter of credit obligation and (ii) the swingline commitment. The aggregate amount of swingline loans in any borrowing shall not be subject to a minimum amount or increment. The indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership s and certain of the Partnership s subsidiaries ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions during certain Defaults and during any Event of Default;
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates;
- enter into restrictive agreements; and
- enter into speculative hedging contracts.

This credit agreement also contains a financial covenant that provides that on each date the Partnership makes a Distribution, the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1, with a permitted increase to 5.5 to 1 during a specified Acquisition Period (as such terms are used in this credit agreement).

As of August 31, 2007, there was a balance of $969.4 million in revolving credit loans (including $107.4 million in Swingline loans) and $57.3 million in letters of credit. The weighted average interest rate on the total amount outstanding at August 31, 2007, was 6.01%. The total amount available under the ETP Credit Facility, as of August 31, 2007, which is reduced by any amounts outstanding under the swingline loan and letters of credit, was $973.3 million. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership s subsidiaries. In connection with entering into the credit agreement for the ETP Credit Facility, all guarantees by ETC OLP, Titan and their direct and indirect wholly-owned subsidiaries of the ETP Senior Notes were released and discharged. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

ETP Term Loan. On October 5, 2007, we entered into a credit agreement providing for a $310 million, 364-day term loan credit facility (the Term Loan Agreement). Borrowings under the Term Loan Agreement were used to fund the purchase price for the Canyon acquisition and for general corporate purposes. The facility is a single draw term loan with an applicable Eurodollar rate plus 0.600% per annum based on our current rating by the rating agencies or at Base Rate for designated period. The indebtedness under the Term Loan Agreement is unsecured and is not guaranteed by any of our subsidiaries. Borrowings under the Term Loan Agreement, upon proper notice to the administrative agent, may be prepaid in whole or in part without premium or penalty. The Term Loan Agreement requires any proceeds received from debt or equity issuance, assets sales, or accordion increases be used to make a mandatory prepayment on the outstanding loan balance. The Term Loan Agreement contains covenants that are similar to the covenants of our ETP Credit Facility.

Prior ETP Credit Facilities. On September 25, 2006, we exercised the accordion feature of the previously existing revolving credit facility and expanded the amount of the facility from $1.3 billion to $1.5 billion. Amounts borrowed under the previously existing

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revolving credit facility bore interest at a rate based on either a Eurodollar rate or a prime rate. The previously existing revolving credit facility had a swingline loan option with a maximum borrowing of $75.0 million at a daily rate based on LIBOR. The commitment fee payable on the unused portion of the facility varied based on our credit rating and the maximum fee was 0.175%. The previously existing revolving credit facility was fully and unconditionally guaranteed by ETC OLP and Titan and all of their direct and indirect wholly-owned subsidiaries of ETP. The previously existing revolving credit facility was unsecured and had equal rights to holders of our other current and future unsecured debt.

On October 18, 2006 we paid and retired a $250 million unsecured revolving credit facility which matured under its terms on December 1, 2006. Amounts borrowed under this facility bore interest at a rate based on either a Eurodollar rate or a base rate. The maximum commitment fee payable on the unused portion of the facility was 0.25%. The $250 million revolving credit facility was fully and unconditionally guaranteed by ETC OLP and all of the direct and indirect wholly-owned subsidiaries of ETC OLP.

HOLP Facilities

Effective August 31, 2006, HOLP entered into the Fourth Amended and Restated Credit Agreement, a $75 million Senior Revolving Facility available through June 30, 2011 (the HOLP Facility) which may be expanded to $150 million. The HOLP Facility has a swingline loan option with a maximum borrowing of $10 million at a prime rate. Amounts borrowed under the HOLP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility (total book value as of August 31, 2007 of approximately $1.2 billion). There was no balance outstanding on the HOLP Facility as of August 31, 2007. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Facility. There were outstanding letters of credit under the HOLP Facility of $1.0 million at August 31, 2007. The sum of the loans made under the HOLP Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the maximum amount of the HOLP Facility.

Debt Covenants

The agreements for each of the Senior Notes, Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the revolving credit facilities contain customary restrictive covenants applicable to ETP and the Operating Partnerships, including the achievement of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The most restrictive of these covenants require us to maintain ratios of Consolidated Funded Indebtedness to Consolidated EBITDA, as defined in the agreements, for the specified four fiscal quarter period of not greater than 5.0 to 1.0, with a permitted increase to 5.5 to 1.0 during a specified Acquisition Period (these terms are defined in the agreement related to the ETP Credit Facility), Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the credit agreement related to the ETP Credit Facility and the note agreements related to the HOLP Notes) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the credit agreement related to the ETP Credit Facility and the note agreements related to the HOLP Notes) of not less than 2.25 to 1. The Consolidated EBITDA used to determine these ratios is calculated in accordance with these debt agreements. For purposes of calculating these ratios, Consolidated EBITDA is based upon our EBITDA, as adjusted for the most recent four quarterly periods, and modified to give pro forma effect for acquisitions and divestitures 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. These debt agreements also provide that the Operating Partnerships may declare, make, or incur a liability to make, restricted payments 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 with respect to the immediately preceding quarter; (b) no default or event of default exists before such restricted payments; and (c) each Operating Partnership s restricted payment is not greater than the product of each Operating Partnership s Percentage of Aggregate Available Cash multiplied by the Aggregate Partner Obligations (as these terms are similarly defined in the bank credit facilities and the Note Agreements). The note agreements related to the HOLP Notes further provide that HOLP s Available Cash is required to reflect a reserve equal to 50% of the interest to be paid on the notes and 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, a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates.

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Failure to comply with the various restrictive and affirmative covenants of our bank credit facilities and the Note Agreements could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Partnerships ability to incur additional debt and/or our ability to pay distributions. We are required to measure these financial tests and covenants quarterly and were in compliance with all requirements, tests, limitations, and covenants related to the Partnership s, Transwestern s and HOLP s debt agreements as of August 31, 2007.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of August 31, 2007:

		Payments Due by Period			
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Long-term debt	$ 3,674,008	$ 47,031	$ 85,884	$ 1,023,326	$ 2,517,767
Interest on fixed rate long-term debt (a)	1,952,088	167,744	354,086	340,718	1,089,540
Payments on derivatives	6,197	5,233	964		
Purchase commitments (b)	717,350	607,854	109,496		
Operating lease obligations	98,788	13,492	27,249	29,877	28,170
Totals	$ 6,448,431	$ 841,354	$ 577,679	$ 1,393,921	$ 3,635,477

(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 Facilities and Revolving Credit Facility Swingline Loan options. As of August 31, 2007, variable rate interest on our outstanding balance of variable rate debt of $969.4 million would be $58.3 million on an annual basis. See Note 5 Debt Obligations to the consolidated financial statements in Item 8 of this report for further discussion of the long-term debt classifications and the maturity dates and interest rates related to long-term debt.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for propane and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the August 31, 2007 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated.

In August 2007 and in connection with a reimbursable agreement entered into by MEP with a financial institution, we executed a percentage guaranty with the same financial institution whereby we would be liable for our 50% of any defaulted payments not made by MEP, plus interest. The reimbursable agreement has a commitment up to $197.0 million, as amended, and expires in September 2008.

Cash Distributions

We will use our cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders. Under our 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 (as defined in our partnership agreement) 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 our operations.

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Distributions declared during the years ended August 31, 2007, 2006 and 2005 are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Fiscal Year 2007	July 2, 2007	July 16, 2007	$ 0.80625
	April 6, 2007	April 13, 2007	$ 0.78750
	January 4, 2007	January 15, 2007	$ 0.76875
	October 5, 2006	October 16, 2006	$ 0.75000
Fiscal Year 2006	June 30, 2006	July 14, 2006	$ 0.63750
	June 30, 2006 (1)	July 14, 2006	$ 0.03250
	March 24, 2006	April 14, 2006	$ 0.58750
	January 4, 2006	January 13, 2006	$ 0.55000
	September 30, 2005	October 14, 2005	$ 0.50000
Fiscal Year 2005	July 8, 2005	July 14, 2005	$ 0.48750
	March 16, 2005	April 14, 2005	$ 0.46250
	January 5, 2005	January 14, 2005	$ 0.43750
	October 7, 2004	October 15, 2004	$ 0.41250

(1) Special SCANA distribution On June 20, 2006, the Board of Directors of our General Partner declared a special distribution of $0.0325 per Limited Partner Unit related to the proceeds we received in connection with the SCANA litigation settlement. This distribution was paid on July 14, 2006 to the holders of record of our Common and Class F Units as of the close of business on June 30, 2006. This special one-time payment was approved following a determination of the Litigation Committee of our General Partner to distribute all the net distributable litigation proceeds we received in accordance with our partnership agreement. The special distribution also included a payment distribution of $3.6 million to the holder of our Class C Units for that amount that would otherwise have been distributed to our General Partner. See discussion in Notes 6 and 9 of our consolidated financial statements for further information.

On September 25, 2007, we announced the declaration of a cash distribution for the fourth quarter ended August 31, 2007 of $0.825 per Common Unit, or $3.30 annually, an increase of $0.075 per Common Unit on an annualized basis. The distribution was paid on October 15, 2007 to Unitholders of record at the close of business on October 5, 2007.

The total amount of distributions (all from Available Cash from our operating surplus) declared during the years ended August 31, 2007, 2006 and 2005 are as follows:

	2007	2006	2005
Limited Partners -			
Common Units	$ 366,180	$ 248,237	$ 173,802
Class C Units (1)		3,599	
Class F Units		3,232	
Class G Units	40,598		
General Partners -			
2% Ownership	12,701	6,981	4,390
Incentive Distribution Rights	203,069	81,722	28,847
	$ 622,548	$ 343,771	$ 207,039

(1) Special SCANA distribution see discussion above.

New Accounting Standards

FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109*, (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. We adopted this statement on September 1, 2007. We are continuing to evaluate the impact of FIN 48, but at this time we believe that the adoption of FIN 48 will not have a significant impact on our consolidated financial statements.

FASB Staff Position No. EITF 00-19-2, *Accounting for Registration Payment Arrangements* (FSP 00-19-2). FSP 00-19-2, issued in December 2006, provides guidance related to the accounting for registration payment arrangements. FSP 00-19-2 specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate arrangement or included as a provision of a financial instrument or arrangement, should be separately recognized and measured in accordance with FASB No. 5, *Accounting for Contingencies* (SFAS No. 5). FSP 00-19-2 requires that if the transfer of consideration under a registration payment arrangement is probable and can be reasonably estimated at inception, the contingent liability under such arrangement shall be included in the allocation of proceeds from the related financing transaction using the measurement guidance in SFAS No. 5. We adopted this Staff Position on September 1, 2007 and the impact was not significant.

SFAS No. 154*, Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3* (SFAS 154). 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. Management adopted the provisions of SFAS 154 on September 1, 2006, with no material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 157, *Fair Value Measurement*, (SFAS 157). This standard provides guidance for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our fiscal year beginning January 1, 2008 (see Note 16 to our consolidated financial statements).

SFAS Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of SFAS Statements No. 87, 88, 106 and 132(R)*, (SFAS 158). Issued in September 2006, this statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multi-employer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. We adopted the recognition and disclosure provisions of SFAS 158 on December 1, 2006 in connection with our acquisition of Transwestern, the effect of which was not material. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. Management does not believe the adoption of the measurement provisions of this statement will have a material impact on our financial statements. We plan to adopt the measurement provisions of this statement when required during our calendar year beginning January 1, 2008 (see Note 16 to our consolidated financial statements).

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*, (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment applies to all entities with available-for-sale and trading securities. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes the choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (discussed above). We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our calendar year beginning January 1, 2008 (see Note 16 to our consolidated financial statements).

SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). In September 2006, the Securities and Exchange Commission (SEC) provided guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 establishes a dual approach that requires quantification of financial statement errors based on the effects of the error on each of the company s financial statements and the related financial statement disclosures. SAB 108 is effective for fiscal years ending after November 15, 2006. We adopted SAB 108 on August 31, 2007. The adoption did not have a material impact on our consolidated financial statements.

Critical Accounting Policies and Estimates

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 to our consolidated financial statements.

Use of 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 accruals for 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. As is normal in the natural gas industry, our most current month s financial results for our midstream and transportation and storage segments are estimated using volume estimates and market prices. Variances in these estimates, including variances in volume estimates, are inherent in our business. Actual results could differ from our estimates if the underlying assumptions prove to be incorrect, and such differences could be material.

Revenue Recognition. Revenues for sales of natural gas, 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.

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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 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.

Our intrastate transportation and storage segment and interstate transportation segment results are determined primarily by the amount of capacity customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. 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 (iv) a combination of the three, generally payable monthly. The intrastate 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.

Transwestern is subject to FERC regulations. As a result, FERC may require the refund of revenues collected during the pendency of a rate proceeding in a final order. Transwestern establishes reserves for these potential refunds, as appropriate. No such reserves were required at August 31, 2007.

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 02-3), which requires revenue and costs related to energy trading contracts to be presented on a net basis in the income statement.

Regulatory Assets and Liabilities. Transwestern is subject to regulation by certain state and federal authorities, is part of our interstate transportation segment and has accounting policies that conform to Statement of Financial Accounting Standards No. 71 (As Amended), *Accounting for the Effects of Certain Types of Regulation* (SFAS 71), which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management s assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

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 forwards, futures, swaps, options and certain basis contracts as cash flow hedging instruments. Certain contracts are not accounted for as hedges and, in accordance with SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), the gains and losses resulting from changes in the fair value of these contracts are recorded on a current basis on the statement of operations. 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. The gains and losses on the natural gas derivative contracts that are entered into for trading purposes are recognized in the midstream and transportation and storage revenue on a net basis in the consolidated statement of operations. The non-trading gains and losses for natural gas contracts are recorded as cost of products sold in the consolidated statement of operations. On our contracts that are designated as cash flow hedges 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 options. 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. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for further discussion regarding our derivative activities.

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 and intangibles with infinite lives 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.

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 3 to 80 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. For those intangible assets that do not have indefinite lives, 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, asset values or estimated lives 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.

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 our 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.

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Legal Matters. We are subject to litigation and regulatory proceedings as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from claims, orders, judgments or settlements. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. We expense legal costs as incurred, and all recorded legal liabilities are revised as required as better information becomes available to us. The factors we consider when recording an accrual for contingencies include, among others: (i) the opinions and views of our legal counsel; (ii) our previous experience; and (iii) the decision of our management as to how we intend to respond to the complaints.

For more information on our litigation and contingencies, see Note 9 to our consolidated financial statements included in Item 8 in this report.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this prospectus, words such as anticipate, project, expect, plan, goal, fore intend, could, believe, may, and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor 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. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the amount of natural gas transported on our pipelines and gathering systems;
- the level of throughput in our natural gas processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and natural gas liquids, or NGLs;
- energy prices generally;
- the prices of natural gas and propane 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, propane 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;

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;

governmental regulation and taxation;

changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;

- hazards or operating risks incidental to the gathering, treating, processing and transporting 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, interstate pipeline companies and propane distribution companies;
- 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 our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities;
- the availability and cost of capital and our ability to access certain capital sources;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under Risk Factors in Item 1A of this annual report.

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.

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 in our midstream and intrastate transportation and storage operations. 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 Chief Executive Officer, Chief Financial Officer, Chief Administrative and Compliance Officer, Treasurer, President Midstream, Controller of our midstream and intrastate transportation and storage operations, and Senior Vice President Commercial Optimization of our midstream and transportation and storage operations, sets forth risk management policies and objectives. The committee 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. We do not engage in any derivative related activities in our interstate transportation segment.

In our retail propane business, the market price of propane is often subject to volatility 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. The propane is then stored at both our customer service locations and in major storage facilities for future resale.

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Non-trading Activities

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis swaps 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 propane 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 on 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 also utilize forward purchase contracts to acquire a portion of the propane that we resell to our customers, which allows us to manage our exposure to unfavorable changes in commodity prices and to assure adequate physical supply. We account for such physical contracts under the normal purchases and sales exception of SFAS 133.

In connection with the acquisition of the HPL System, we acquired certain physical forward contracts that contain embedded options that we have not designated as a normal purchase and sale nor were the contracts 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 intrastate transportation and storage segments, we account for certain of our derivatives as cash flow hedges under SFAS 133. All derivatives are recognized on the balance sheet at fair value as price risk management assets and liabilities. The changes in the fair value of price risk management assets and liabilities that are designated, 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. For those derivatives 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.

We also attempt to maintain balanced positions in our midstream and intrastate 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

We have a risk management policy that provides for our marketing and trading operations to assume limited market price risk. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain transactions and forward contracts are considered trading for accounting purposes and are executed with the use of a combination of financial instruments including, but not limited to, basis swaps and gas daily contracts. 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 complement 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 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

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market prices, newly originated transactions, and the timing and settlement of contracts. Forward physical contracts associated with the trading activities are marked to market and included in revenue on our consolidated statement of operations because they do not meet normal purchases and sales exception of SFAS 133.

As a result of our trading activities and the use of derivative financial instruments that may not qualify for hedge accounting in our midstream and intrastate transportation and storage segments, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk management committee, which includes members of senior management, and predefined limits and authorizations set forth by our risk management policy.

Commodity-related Derivatives

Our commodity-related price risk management assets and liabilities as of August 31, 2007 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	14,195,262	2007-2009	$ 5,551
Swing Swaps IFERC	Gas	7,282,500	2007-2008	(514)
Fixed Swaps/Futures	Gas	(590,000)	2007-2009	1,298
Forward Physical Contracts	Gas	(6,437,413)	2007-2008	343
Options	Gas	(976,000)	2007-2008	(346)
Forward/Swaps - in Gallons	Propane/Ethane	8,862,000	2007-2008	777
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(4,922,500)	2007-2008	$ 2,390
Swing Swaps IFERC	Gas	(21,250,000)	2007	(33)
Forward Physical Contracts	Gas		2007	323
Fixed Swaps/Futures	Gas	(10,275,000)	2007	(177)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(10,962,500)	2007-2008	$ 124
Fixed Swaps/Futures	Gas	(11,230,000)	2007-2009	23,078

Credit Risk

We maintain credit policies with regard to our counterparties that we believe significantly minimize overall credit risk. These policies include an evaluation of potential counterparties financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies (LDCs). This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

Sensitivity analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of August 31, 2007. It also assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

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	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Fixed Swaps/Futures	(11,820,000)	$ 24,376	$ 10,929
Basis Swaps IFERC/NYMEX	3,232,762	5,675	1,091
Swing Swaps IFERC	7,282,500	(514)	467
Options	(976,000)	(346)	190
Forward Physical Contracts	(6,437,413)	343	3,442
Propane Forwards/Swaps (in Gallons)	8,862,000	777	3,495
Trading Derivatives			
Swing Swaps IFERC	(21,250,000)	(33)	1,737
Basic Swaps IFERC/NYMEX	(4,922,500)	2,390	17
Forward Physical Contracts		323	2,980
Fixed Swaps/Futures	(10,275,000)	(177)	5,579

The table below summarizes our positions and values as of August 31, 2006. It also assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Fixed Swaps/Futures	(34,265,000)	$ 1,873	$ 42,615
Basis Swaps IFERC/NYMEX	(873,860)	(9,234)	1,594
Swing Swaps IFERC	(37,220,448)	2,618	514
Options	(1,046,000)	21,653	5,189
Forward Physical Contracts	(7,986,000)	(21,653)	5,189
Propane Forwards/Swaps (in Gallons)	24,066,000	199	2,766
Trading Derivatives			
Swing Swaps IFERC		(31)	205
Basic Swaps IFERC/NYMEX	(2,572,500)	21,995	701
Forward Physical Contracts	(455,000)	(68)	75

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10 percent change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in our consolidated results of operations or in accumulated other comprehensive income. In the event of an actual 10 percent change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10 percent due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

We are exposed to market risk for increases in interest rates, primarily as a result of our variable rate debt and, in particular, our bank credit facilities. To the extent interest rates increase, our interest expense for our revolving credit facilities will also increase. At August 31, 2007, we had $969.4 million of variable rate debt outstanding and a pay fixed receive float interest rate swap with a notional amount of $125.0 million that is not designated as a hedge. Changes in fair value of the swap are recorded in other income on the consolidated statement of operations. A hypothetical change of 100 basis points in the underlying interest rate and a corresponding parallel shift in the LIBOR yield curve would have a net effect of $7.9 million in interest expense and other income, in the aggregate, on an annual basis.

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We are also subject to interest rate risk on our fixed rate debt if interest rates decrease. To manage this risk, we may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt. For further information, see Note 10 to our consolidated financial statements.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Energy Transfer Partners, L.P. and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries as of August 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the three years in the period ended August 31, 2007. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Partners, L.P. and subsidiaries as of August 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended August 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Energy Transfer Partners L.P. s internal control over financial reporting as of August 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated October 29, 2007 expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Dallas, Texas

October 29, 2007

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	August 31, 2007	August 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 68,705	$ 26,041
Marketable securities	3,099	2,817
Accounts receivable, net of allowance for doubtful accounts	637,676	675,545
Accounts receivable from related companies	6,900	897
Inventories	192,276	387,140
Deposits paid to vendors	45,490	87,806
Exchanges receivable	32,891	23,221
Price risk management assets	8,958	56,139
Prepaid expenses and other	45,098	42,198
Total current assets	1,041,093	1,301,804
PROPERTY, PLANT AND EQUIPMENT, net	5,548,383	3,313,649
LONG-TERM PRICE RISK MANAGEMENT ASSETS	151	2,192
ADVANCES TO AND INVESTMENT IN AFFILIATES	56,564	41,344
GOODWILL	718,429	604,409
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	343,808	191,615
Total assets	$ 7,708,428	$ 5,455,013

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	August 31, 2007	August 31, 2006
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 487,148	$ 603,140
Accounts payable to related companies	19,471	650
Exchanges payable	34,252	24,722
Customer advances and deposits	81,919	108,836
Accrued wages and benefits	53,109	40,236
Accrued and other current liabilities	192,085	160,698
Price risk management liabilities	2,707	36,918
Income taxes payable	6,234	83
Deferred income taxes	261	629
Current maturities of long-term debt	47,031	40,578
Total current liabilities	924,217	1,016,490
LONG-TERM DEBT, less current maturities	3,626,977	2,589,124
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	685	1,728
DEFERRED INCOME TAXES	100,810	106,842
MINORITY INTERESTS AND OTHER NON-CURRENT LIABILITIES	15,906	3,967
COMMITMENTS AND CONTINGENCIES (Note 9)		
Total liabilities	4,668,595	3,718,151
PARTNERS CAPITAL:		
General Partner	127,046	82,450
Limited Partners:		
Common Unitholders (136,981,221 and 110,726,999 units authorized, issued and outstanding at August 31, 2007 and 2006, respectively)	2,890,140	1,647,345
Class E Unitholders (8,853,832 units authorized, issued and outstanding held by subsidiary and reported as treasury units)		
	3,017,186	1,729,795
Accumulated other comprehensive income, per accompanying statements	22,647	7,067
Total partners capital	3,039,833	1,736,862
Total liabilities and partners capital	$ 7,708,428	$ 5,455,013

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit and unit data)

	Years Ended August 31,		
	2007	**2006**	**2005**
REVENUES:			
Natural gas operations	$ 5,385,892	$ 6,877,512	$ 5,383,625
Retail propane	1,179,073	799,358	641,071
Other	227,072	182,226	144,102
Total revenues	6,792,037	7,859,096	6,168,798
COSTS AND EXPENSES:			
Cost of products sold - natural gas operations	4,207,700	5,963,422	4,911,366
Cost of products sold - retail propane	734,204	493,642	384,186
Cost of products sold - other	136,302	111,252	85,963
Operating expenses	559,600	422,989	319,554
Depreciation and amortization	179,162	117,415	92,943
Selling, general and administrative	145,417	107,505	62,735
Total costs and expenses	5,962,385	7,216,225	5,856,747
OPERATING INCOME	829,652	642,871	312,051
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(175,563)	(113,857)	(93,017)
Loss on extinguishment of debt			(9,550)
Equity in earnings (losses) of affiliates	5,161	(479)	(376)
Gain (loss) on disposal of assets	(6,310)	851	(330)
Interest and other income, net	37,999	14,620	631
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	690,939	544,006	209,409
Income tax expense	(13,658)	(25,920)	(7,295)
INCOME FROM CONTINUING OPERATIONS BEFORE MINORITY INTERESTS	677,281	518,086	202,114
Minority interests	(1,142)	(2,234)	(731)
INCOME FROM CONTINUING OPERATIONS	676,139	515,852	201,383
DISCONTINUED OPERATIONS:			
Income from discontinued operations			5,498
Gain on sale of discontinued operations, net of income tax expense			142,469
Total income from discontinued operations			147,967

NET INCOME		676,139		515,852		349,350
GENERAL PARTNER S INTEREST IN NET INCOME		235,876		118,985		45,442
LIMITED PARTNERS INTEREST IN NET INCOME	$	440,263	$	396,867	$	303,908
BASIC NET INCOME PER LIMITED PARTNER UNIT						
Limited Partners income from continuing operations	$	3.32	$	3.16	$	1.51
Limited Partners income from discontinued operations						1.10
NET INCOME PER LIMITED PARTNER UNIT	$	3.32	$	3.16	$	2.61
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING		132,618,053		109,036,265		97,646,351
DILUTED NET INCOME PER LIMITED PARTNER UNIT						
Limited Partners income from continuing operations	$	3.31	$	3.15	$	1.50
Limited Partners income from discontinued operations						1.10
NET INCOME PER LIMITED PARTNER UNIT	$	3.31	$	3.15	$	2.60
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING		132,877,152		109,334,778		97,831,017

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended August 31,		
	2007	**2006**	**2005**
Net income	$ 676,139	$ 515,852	$ 349,350
Other comprehensive income, net of tax:			
Reclassification adjustment for gains and losses on derivative instruments accounted for as cash flow hedges included in net income	(160,420)	(74,507)	25,280
Change in value of derivative instruments accounted for as cash flow hedges	175,720	167,525	(111,617)
Change in value of available-for-sale securities	280	(634)	988
Comprehensive income	$ 691,719	$ 608,236	$ 264,001
Reconciliation of Accumulated Other Comprehensive Income (Loss)			
Balance, beginning of period	$ 7,067	$ (85,317)	$ 32
Current period reclassification to earnings	(160,420)	(74,507)	25,280
Current period change in value	176,000	166,891	(110,629)
Balance, end of period	$ 22,647	$ 7,067	$ (85,317)
Components of Accumulated Other Comprehensive Income (Loss), net of tax			
Commodity related derivative hedges	$ 21,192	$ 2,095	$ (84,523)
Interest rate derivative hedges	874	4,672	(1,729)
Available-for-sale securities	581	300	935
Balance, end of period	$ 22,647	$ 7,067	$ (85,317)

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands)

			Limited Partners		
	General Partner	Common Unitholders	Class C Unitholders	Class F Unitholders	Class G Unitholders
Balance, August 31, 2004	$ 26,761	$ 720,187	$	$	$
Distributions to partners	(33,237)	(173,802)			
Issuance of Common Units in connection with certain acquisitions		2,500			
Issuance of Common Units		507,724			
General Partner capital contribution	10,418				
Unit-based compensation expense		1,608			
Net income	45,442	303,908			
Balance, August 31, 2005	49,384	1,362,125			
Distributions to partners	(88,703)	(248,237)	(3,599)	(3,232)	
Issuance of Common and Class F Units to Energy Transfer Equity, LP		38,907		93,476	
Issuance of Common Units in connection with certain acquisitions		4,000			
Conversion to Common Units		93,268		(93,268)	
General Partner capital contribution	2,784				
Unit-based compensation expense		7,038			
Net income	118,985	390,244	3,599	3,024	
Balance, August 31, 2006	$ 82,450	$ 1,647,345	$	$	$
Distributions to partners	(215,770)	(366,180)			(40,598)
Issuance of Class G Units to Energy Transfer Equity, LP					1,200,000
Conversion to Common Units		1,208,394			(1,208,394)
General Partner capital contribution	24,490				
Tax effect of remedial income allocation from tax amortization of goodwill		(1,161)			
Unit-based compensation expense		10,471			
Net income	235,876	391,271			48,992
Balance, August 31, 2007	$ 127,046	$ 2,890,140	$	$	$

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended August 31, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 676,139	$ 515,852	$ 349,350
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization related to continuing and discontinued operations	179,162	117,415	94,490
Amortization of finance costs charged to interest expense	4,061	2,807	4,049
Loss on extinguishment of debt			9,550
Provision for loss on accounts receivable	4,229	1,723	5,523
(Gain) loss on disposal of assets	6,310	(851)	330
Gain on sale of discontinued operations before income tax expense			(146,401)
Non-cash compensation on unit grants and other	10,471	7,038	1,608
Undistributed (earnings) losses of equity of affiliates	(5,161)	479	342
Deferred income taxes	(4,042)	(3,827)	1,289
Undistributed minority interests	381	1,382	540
Net change in operating assets and liabilities, net of acquisitions	241,182	(98,134)	(151,252)
Net cash provided by operating activities	$ 1,112,732	$ 543,884	$ 169,418
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions, net of cash acquired	(90,695)	(586,185)	(1,131,844)
Working capital settlement on prior year acquisitions		19,653	
Capital expenditures	(1,096,664)	(680,164)	(196,459)
Proceeds from the sale of discontinued operations			191,606
Advances to and investment in affiliates	(993,866)	(4,651)	(2,355)
Proceeds from the sale of assets	23,135	6,941	5,303
Net cash used in investing activities	(2,158,090)	(1,244,406)	(1,133,749)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	4,757,971	2,829,748	2,954,034
Principal payments on debt	(4,260,494)	(1,917,451)	(2,337,931)
Proceeds from borrowings from affiliates			174,624
Payments on borrowings from affiliates			(174,624)
Net proceeds from issuance of Limited Partner Units	1,200,000	132,383	507,724
Capital contribution from General Partner	24,490	2,784	10,418
Distributions to partners	(622,548)	(343,771)	(207,039)
Debt issuance costs	(11,397)	(2,044)	(19,706)
Net cash provided by financing activities	1,088,022	701,649	907,500
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	42,664	1,127	(56,831)
CASH AND CASH EQUIVALENTS, beginning of period	26,041	24,914	81,745

CASH AND CASH EQUIVALENTS, end of period	$ 68,705	$ 26,041	$ 24,914

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in thousands, except per unit data)

1. OPERATIONS AND ORGANIZATION:

Financial Statement Presentation

The accompanying consolidated financial statements of Energy Transfer Partners, L.P. and subsidiaries (the Partnership or ETP) presented herein for the years ended August 31, 2007, 2006 and 2005, have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and pursuant to the rules and regulations of the Securities and Exchange Commission. We consolidate all majority-owned subsidiaries. We recognize a minority interest liability and minority interest expense for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation.

The consolidated financial statements of the Partnership presented herein for the year ended August 31, 2007 include the results of operations for La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP), Heritage Operating, L.P. (HOLP), Heritage Holdings, Inc. (HHI) and Titan Energy Partners, L.P. (Titan) for the entire period from September 1, 2006 through August 31, 2007. The results of operations for Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, LLC (ETC MEP) are included since the date of the Transwestern acquisition (December 1, 2006).

The consolidated financial statements of the Partnership presented herein for the year ended August 31, 2006 include the results of operations for ETC OLP, HOLP and HHI for the entire period from September 1, 2005 through August 31, 2006. The results of operations for Titan are included since the date of acquisition (June 1, 2006).

The consolidated financial statements of the Partnership presented herein for the year ended August 31, 2005 include the results of operations for ETC OLP, HOLP and HHI for the entire period from September 1, 2004 through August 31, 2005 and the Houston pipeline system (HPL System) since the date of acquisition (January 26, 2005).

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

Certain prior period amounts have been reclassified to conform with the 2007 presentation. These reclassifications had no impact on net income or total partners capital.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities consist of four reportable segments, which are conducted through four subsidiary operating partnerships (collectively the Operating Partnerships).

ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations;

ET Interstate, the parent company of Transwestern and ETC MEP, both Delaware limited liability companies engaged in interstate transportation of natural gas;

HOLP, a Delaware limited partnership primarily engaged in retail propane operations; and

Titan, a Delaware limited partnership engaged in retail propane operations.

The Partnership, the Operating Partnerships, and their subsidiaries are collectively referred to in this report as we , us , ETP , Energy Transfer or the Partnership.

ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, natural gas intrastate pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and natural gas liquids (NGLs) in the states of Texas, Louisiana, New Mexico, Utah and Colorado.

ETC OLP owns an interest in and operates approximately 14,100 miles of in service natural gas gathering and intrastate transportation pipelines with an additional 480 miles of intrastate pipeline under construction, three natural gas processing plants, twelve natural gas treating facilities, ten natural gas conditioning facilities and three natural gas storage facilities located in Texas.

The midstream operations focus on the gathering, compression, treating, blending, processing, and marketing of natural gas, primarily on or through the Southeast Texas System, and marketing operations related to our producer services business. We also own approximately 27 miles of gathering pipelines in New Mexico and recently acquired 1,800 miles of gathering pipelines and six natural gas conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah as further described below. Revenue is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, transported, purchased and sold through our pipelines (excluding the transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

The intrastate transportation and storage operations focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Revenue is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline on an interruptible basis. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The intrastate transportation and storage operations also consist of the HPL System which generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies. The use of the Bammel storage reservoir allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. The HPL System also transports natural gas for a variety of third party customers.

Our interstate transportation operations principally focus on natural gas transportation of Transwestern, which owns and operates approximately 2,400 miles of interstate natural gas pipeline extending from Texas through the San Juan Basin to the California border. Transwestern is a major natural gas transporter to the California border and delivers natural gas from the east end of its system to Texas intrastate and Midwest markets. The Transwestern pipeline interconnects with our existing intrastate pipelines in West Texas. The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

Our retail propane segment sells propane and propane-related products and services. The HOLP and Titan customer base includes residential, commercial, industrial and agricultural customers.

2. SIGNIFICANT ACQUISITIONS AND DISPOSITIONS:

Significant Acquisitions:

Fiscal year 2007

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (GE) and Southern Union Company (Southern Union), we acquired the member interests in CCE Holdings, LLC (CCEH) from GE and certain other investors for $1,000,000. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to Energy Transfer Equity, L.P. simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP s 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and separate segment of ETP.

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The total acquisition cost for Transwestern, net of cash acquired, was as follows:

Basis of investment in CCEH at November 30, 2006	$ 956,348
Distributions received on December 1, 2006	(6,217)
Fair value of short-term debt assumed	13,000
Fair value of long-term debt assumed	519,377
Other assumed long-term indebtedness	10,096
Current liabilities assumed	35,781
Cash acquired	(3,386)
Acquisition costs incurred	11,696
Total	$ 1,536,695

In September 2006 we acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of $30,589 in cash. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $25,000 to be determined eighteen months from the closing date. We will record the required adjustment to the purchase price allocation when the amount of actual contingent consideration is determinable beyond a reasonable doubt. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas and are included in our midstream operating segment. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility.

In December 2006 we purchased a natural gas gathering system in north Texas for $32,000 in cash. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $21,000 to be determined two years after the closing date. We will record the required adjustment to the purchase price allocation when the amount of the actual contingent consideration is determinable beyond a reasonable doubt. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility.

During the fiscal year ended August 31, 2007, HOLP and Titan collectively acquired substantially all of the assets of five propane businesses. The aggregate purchase price for these acquisitions totaled $17,592 which included $15,478 of cash paid, net of cash acquired, and liabilities assumed of $2,114. The cash paid for acquisitions was financed primarily with ETP s and HOLP s Senior Revolving Credit Facilities.

Except for the acquisition of the 50% member interests in CCEH, these acquisitions were accounted for under the purchase method of accounting in accordance with SFAS No. 141 and the purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. The acquisition of 100% of Transwestern has been accounted for under the purchase method of accounting since the acquisition on December 1, 2006. Pro forma effects of the Transwestern acquisition are discussed below. In the aggregate, the other acquisitions described above are not material for pro forma disclosure purposes.

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The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for these fiscal year 2007 acquisitions described above, net of cash acquired:

	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$	$ 20,062	$ 1,111
Inventory		895	414
Prepaid and other current assets		11,842	57
Investment in unconsolidated affiliate	(503)		
Property, plant, and equipment	50,916	1,254,968	8,035
Intangibles and other assets	23,015	141,378	3,808
Goodwill		107,550	4,167
Total assets acquired	73,428	1,536,695	17,592
Accounts payable		(1,932)	(381)
Customer advances and deposits		(700)	(254)
Accrued and other current liabilities	(292)	(33,149)	(170)
Short-term debt (paid in December 2006)		(13,000)	
Long-term debt		(519,377)	(1,309)
Other long-term obligations		(10,096)	
Total liabilities assumed	(292)	(578,254)	(2,114)
Net assets acquired	$ 73,136	$ 958,441	$ 15,478

The purchase price for the acquisitions has been initially allocated based on the estimated fair value of the assets acquired and liabilities assumed. The Transwestern allocation was based on the preliminary results of independent appraisals. The purchase price allocations have not been completed and are subject to change. We expect to complete the allocations during the first quarter of fiscal year 2008.

Included in the additions for interstate property, plant and equipment is an aggregate plant acquisition adjustment of $446,154, which represents costs allocated to Transwestern s transmission plant. This amount has not been included in the determination of tariff rates Transwestern charges to its regulated customers. The unamortized balance of this adjustment was $436,594 at August 31, 2007 and is being amortized over 35 years, the composite weighted average estimated remaining life of Transwestern s assets as of the acquisition date.

Regulatory assets, included in intangible and other long-term assets on the condensed consolidated balance sheet, established in the Transwestern purchase price allocation consist of the following:

Accumulated reserve adjustment	$ 42,132
AFUDC gross-up	9,280
Environmental reserves	6,623
South Georgia deferred tax receivable	2,593
Other	9,329
Total Regulatory Assets acquired	$ 69,957

At August 31, 2007, all of Transwestern s regulatory assets are considered probable of recovery in rates.

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We recorded the following intangible assets and goodwill in conjunction with the acquisitions described above:

	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Intangible assets:			
Contract rights and customer lists (6 to 15 years)	$ 23,015	$ 47,582	$
Financing costs (7 to 9 years)		13,410	
Other			3,808
Total intangible assets	23,015	60,992	3,808
Goodwill		107,550	4,167
Total intangible assets and goodwill acquired	$ 23,015	$ 168,542	$ 7,975

Goodwill was warranted because these acquisitions enhance our current operations, and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible. We do not believe that the acquired intangible assets have any significant residual value at the end of their useful life.

Fiscal year 2006

On November 10, 2005, we acquired the remaining 2% limited partnership interests in the HPL System for $16,560 in cash. The purchase price was allocated to property, plant and equipment and the minority interest liability associated with the 2% limited partner interests was eliminated. As a result, the HPL System became a wholly-owned subsidiary of ETC OLP. We also reached a settlement agreement with AEP in November 2005 related to certain inventory and working capital matters associated with the acquisition. The terms of the agreement were not material in relation to our financial position or results of operations.

On June 1, 2006, we acquired all the propane operations of Titan for cash of approximately $548,000, after working capital adjustments and net of cash acquired, and liabilities assumed of approximately $46,000. This acquisition was initially financed by borrowings under the ETP Revolving Credit Facility. Titan s propane assets primarily consisted of retail propane operations in 33 states conducted from 146 district locations located in high growth areas of the U.S. The addition of the Titan assets expanded our retail propane operations into six additional states and several new operating territories in which we did not previously have operations. This expansion further reduced the impact on the propane operations from weather patterns in any one area of the U.S., while continuing our focus on conducting the retail propane operations in attractive high-growth areas. We accounted for the Titan acquisition as a business combination using the purchase method of accounting in accordance with the provisions of SFAS 141. The purchase price was initially allocated based on the estimated fair value of the individual assets acquired and the liabilities assumed at the date of the acquisition based on the preliminary results of an independent appraisal. We completed the purchase allocation during our third quarter of fiscal year 2007 upon the completion of the independent appraisal. The adjustments to the purchase price allocation were not material. Pro forma results of operations due to the Titan acquisition are discussed below.

During the fiscal year ended August 31, 2006, HOLP and Titan collectively acquired substantially all of the assets of eight propane businesses. The aggregate purchase price for these acquisitions totaled $28,902 which included $20,572 of cash paid, net of cash acquired, 99,955 Common Units issued valued at $4,000 and liabilities assumed of $4,327. In the aggregate, these acquisitions are not material for pro forma disclosure purposes. The cash paid for acquisitions was financed primarily with the HOLP Senior Revolving Acquisition Facility.

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The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for these fiscal year 2006 acquisitions:

	Titan June 2006	Midstream and Transportation and Storage Acquisitions (Aggregated)	Other Propane Acquisitions (Aggregated)
Cash and equivalents	$ 24,458	$	$ 3
Accounts receivable	20,304	396	1,702
Inventory	11,417	20	795
Prepaid and other current assets	2,055	4	83
Investments in unconsolidated affiliate		(50)	
Price risk management assets	720		
Property, plant, and equipment	202,598	308	19,276
Intangibles and other assets	74,532		5,342
Goodwill	278,149		1,701
Other long-term assets	5,055		
Total assets acquired	619,288	678	28,902
Accounts payable	(18,337)	(211)	
Accrued expense	(14,992)	(10)	(1,748)
Customer advances and deposits	(11,356)		
Other current liabilities			
Current maturities of long term debt	(964)		
Long-term debt	(692)		(2,579)
Minority interest		16,667	
Total liabilities assumed	(46,341)	16,446	(4,327)
Net assets acquired	$ 572,947	$ 17,124	$ 24,575

We recorded the following intangible assets in conjunction with these acquisitions:

Customer lists (3-15 years)	$ 37,333
Non-compete agreements (5 to 10 years)	2,315
Software	2,200
Total amortized intangible assets	41,848
Trademarks and trade names	35,395
Goodwill	279,850
Other assets	2,631
Total intangible assets and goodwill acquired	$ 359,724

Goodwill was warranted because these acquisitions enhance our current operations, and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible.

Fiscal year 2005

In November 2004, we acquired the Texas Chalk and Madison Systems from Devon Gas Services for $63,022 in cash which was principally financed with $60,000 from the then existing ETC OLP Revolving Credit Facility. The total purchase price was $65,067 which included $63,022 of cash paid and liabilities assumed of $2,045. These assets include approximately 1,800 miles of gathering and mainline pipeline systems, four natural gas treating plants, condensate stabilization facilities and an 80 MMcf/d gas processing plant. These assets will be integrated into the Southeast Texas System and are expected to provide increased throughput capacity to our existing midstream assets. The acquisition was not material for pro forma disclosure purposes.

In January 2005, we acquired the controlling interests in the HPL System from American Electric Power Corporation (AEP) for approximately $825,000 subject to working capital adjustments. Under the terms of the transaction, the Partnership, through ETC OLP, our wholly-owned subsidiary, acquired all but a 2% limited partner interest in the HPL System. We financed this acquisition through a combination of cash on hand, borrowings under our credit facilities and a private placement with institutional investors of $350,000 of Partnership Common Units. In addition, we acquired working inventory of natural gas stored in the Bammel storage facilities. The total purchase price of $1,350,212 (which included $1,039,521 of cash paid), net of cash acquired and liabilities assumed of $344,663, (including $800 in estimated acquisition costs), was allocated to the assets acquired and liabilities assumed. The HPL System consists of approximately 4,200 miles of intrastate pipeline, substantial storage facilities and related transportation assets. We obtained the final independent valuation for the fiscal year 2005 HPL System acquisition and made the final allocations of the purchase price to the acquired assets during the second quarter of fiscal year 2006. The final adjustments, which did not have a material impact on our financial position, resulted in a reduction of $45,820 to the amount allocated to pad gas and an increase of an equal amount to acquired depreciable assets. The acquisition enables us to expand our current transportation systems into areas where we previously did not have a presence and, in combination with our current midstream assets, provides the premier producing basins in Texas with direct access to the Houston Ship Channel corridor. The HPL System is included in our intrastate transportation and storage operating segment.

During the year ended August 31, 2005, HOLP acquired substantially all of the assets of ten propane businesses. The aggregate purchase price for these acquisitions totaled $30,772 which included $25,462 of cash paid, net of cash acquired, 120,550 Common Units on a post-split basis issued valued at $2,500 and liabilities assumed of $2,810. In the aggregate, these acquisitions are not material for pro forma disclosure purposes. The cash paid for acquisitions was financed primarily with the HOLP Senior Revolving Acquisition Facility.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for these acquisitions:

	Texas Chalk and Madison Systems November 2004	Initial HPL Acquisition January 2005	HOLP Acquisitions (Aggregated)
Cash and equivalents	$	$ 191	$ 5
Accounts receivable		321,214	875
Inventory		132,095	584
Other current assets		8,672	215
Investments in unconsolidated affiliate		32,940	
Price risk management assets		30,300	
Property, plant, and equipment	65,067	823,360	18,592
Intangibles		1,440	5,971
Goodwill			4,535
Total assets acquired	65,067	1,350,212	30,777
Accounts payable	(525)	(253,784)	(233)
Accrued expenses	(1,520)	(18,344)	(181)
Other current liabilities		(11,829)	(227)
Other liabilities		(15,277)	
Price risk management liabilities		(30,300)	
Long-term debt			(2,169)
Minority interest		(15,129)	
Total liabilities assumed	(2,045)	(344,663)	(2,810)
Net assets acquired	$ 63,022	$ 1,005,549	$ 27,967

We recorded the following intangible assets in conjunction with these acquisitions:

Customer lists (3-15 years)	$ 3,456
Non-compete agreements (5 to 10 years)	1,326
Total amortized intangible assets	4,782
Trademarks and trade names	2,629
Goodwill	4,535
Total intangible assets and goodwill acquired	$ 11,946

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Goodwill was warranted because these acquisitions enhance our current operations and certain acquisitions are expected to reduce costs through synergies with existing operations. We assigned all of the goodwill acquired to the retail propane segment of HOLP. We expect the entire $4,535 of goodwill acquired to be tax deductible.

Pro Forma Results of Operations (Unaudited)

The following unaudited pro forma consolidated results of operations for the year ended August 31, 2007 are presented as if the Transwestern acquisition had been made on September 1, 2005. The operations of Transwestern have been included in our statements of operations since acquisition on December 1, 2006. The unaudited pro forma consolidated results of operations for the year ended August 31, 2006 are presented as if the Transwestern and Titan acquisitions had been made on September 1, 2005. The pro forma consolidated results of operations for the year ended August 31, 2005 are presented as if the Titan and HPL acquisitions had been made on September 1, 2004. The pro forma consolidated net income and earnings per unit include the income from discontinued operations as presented on the consolidated statements of operations for the year ended August 31, 2005.

	Years Ended August 31,		
	2007	**2006**	**2005**
Revenues	$ 6,850,929	$ 8,421,824	$ 8,210,903
Net income	$ 693,045	$ 587,873	$ 730,208
Limited Partners interest in net income	$ 456,831	$ 441,815	$ 674,111
Basic earnings per Limited Partner Unit	$ 3.31	$ 2.93	$ 4.15
Diluted earnings per Limited Partner Unit	$ 3.30	$ 2.93	$ 4.14

Included in the pro forma results of operations for our fiscal year ended August 31, 2005 is approximately $350.2 million of Titan income related to the cancellation of debt through Titan s bankruptcy process, net of $24.9 million of Titan reorganization expenses and $10.8 million of Titan fresh start expenses. This income is not excluded from our pro forma income for the year ended August 31, 2005 as it does not result directly from the Titan acquisition. However, this income is non-recurring in nature and we do not expect to realize similar income in the future.

The pro forma consolidated results of operations include adjustments to give effect to depreciation on the step-up of property, plant and equipment, amortization of customer lists, interest expense on acquisition debt, and certain other adjustments. The pro forma consolidated results of operations exclude (1) the midstream and five propane acquisitions during the year ended August 31, 2007, (2) the acquisition of the remaining 2% interest of HPL and the eight propane businesses acquired during the year ended August 31, 2006, and (3) the propane acquisitions and Texas Chalk and Madison Systems acquisitions completed during the year ended August 31, 2005, as the impact of such acquisitions is not material. The pro forma 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.

Dispositions

On April 14, 2005, we sold our Oklahoma gathering, treating and processing assets, referred to as the Elk City System, for $191,606 in cash and recorded a gain on the sale during the fiscal year 2005 of $142,469, net of income taxes of $1,829. The Elk City System was included in our midstream segment. The sale of the Elk City System has been accounted for as discontinued operations in accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*. These results are presented as net amounts in the consolidated statements of operations for the year with prior periods restated to conform to the current presentation. Selected operating results for these discontinued operations are as follows:

	Year Ended August 31, 2005
Revenues	$ 105,542
Cost and expenses	(100,044)
Income from discontinued operations	$ 5,498

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3. SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:
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 or other arrangements in which 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 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 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.

We conduct our 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. We also attract 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 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.

We have a risk management policy that provides for our marketing and trading operations to execute limited strategies. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain strategies are considered trading activities for accounting purposes and are accounted for on a net basis in revenues on the consolidated statements of operations. Our trading activities include purchasing and selling natural gas and the use of financial instruments, including basis contracts and gas daily contracts.

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 02-3), which requires revenue and costs related to energy trading contracts to be presented on a net basis in the statement of operations. As a result of our trading activities, discussed in Note 10, and the use of derivative financial instruments that may not qualify for hedge accounting in our midstream and transportation and storage segments, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to the risk management committee which includes members of senior management, and predefined limits and authorizations set forth by our risk management policy.

Our intrastate transportation and storage and interstate transportation segments results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a

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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 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 (iv) a combination of the three, generally payable monthly. Our intrastate transportation and storage segment also generates its revenues and margin from fees charged for storing customers working natural gas in our storage facilities, primarily on the ET Fuel system, and to a lesser extent, on the HPL System.

Our intrastate transportation and storage segment also generates 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, we purchase natural gas from the market, including purchases from the midstream segment s producer services, and from producers at the wellhead. To the extent the natural gas is obtained from producers, it is purchased at a discount to a specified price and is typically resold to customers at a price based on a published index.

We 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 on its HPL System. 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 of the HPL System, we have continually managed our positions to enhance the future profitability of our storage position. 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. However, we cannot 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.

Regulatory Accounting

Regulatory Assets and Liabilities Transwestern is subject to regulation by certain state and federal authorities, is part of our interstate transportation segment and has accounting policies that conform to Statement of Financial Accounting Standards No. 71 (As Amended), *Accounting for the Effects of Certain Types of Regulation* (SFAS 71), which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management s assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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 natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the month ended August 31, 2007 represent the actual results in all material respects.

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Some of the other more significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, estimates related to our unit-based compensations plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, such balances may be in excess of the Federal Deposit Insurance Corporation (FDIC) insurance limit.

The net change in cash due to changes in operating assets and liabilities (net of acquisitions) is comprised as follows:

	Years Ended August 31,		
	2007	2006	2005
Accounts receivable	$ 54,347	$ 189,719	$ (242,885)
Accounts receivable from related companies	(6,003)	3,717	(4,445)
Inventories	196,173	(83,448)	(105,441)
Deposits paid to vendors	42,316	(22,772)	(62,012)
Exchanges receivable	(3,406)	12,402	(18,412)
Prepaid expenses and other	11,281	(27,574)	(4,650)
Intangibles and other long-term assets	(2,530)	(2,737)	(2,267)
Regulatory assets	663		
Accounts payable	(92,172)	(295,332)	297,968
Accounts payable to related companies	18,564	(467)	(5,194)
Customer advances and deposits	(27,962)	(41,179)	93,762
Exchanges payable	3,000	(9,050)	9,320
Accrued and other current liabilities	12,805	74,373	22,267
Other long-term liabilities	1,460	(13,179)	(834)
Income taxes payable	2,543	(2,103)	(66)
Price risk management liabilities, net	30,103	119,496	(128,363)
Net change in assets and liabilities, net of effect of acquisitions	$ 241,182	$ (98,134)	$ (151,252)

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Noncash financing and supplemental cash flow information is as follows:

	Years Ended August 31, 2007	2006	2005
NONCASH FINANCING ACTIVITIES:			
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 533,625	$ 4,234	$ 2,168
Issuance of Common Units in connection with certain acquisitions	$	$ 4,000	$ 2,500
Transfer of investment in affiliate in purchase of Transwestern (Note 2)	$ 956,348	$	$
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for interest, net of $22,979, $12,605 and $191 capitalized for August 31, 2007, 2006 and 2005, respectively	$ 184,993	$ 121,329	$ 87,589
Cash paid during the period for income taxes	$ 8,583	$ 38,131	$ 7,538

Marketable Securities

Marketable securities we own are classified as available-for-sale securities and are reflected as a current asset on the consolidated balance sheet at fair value.

Accounts Receivable

Our midstream and intrastate transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment, or master set off agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and transportation and storage operations. Management believes that the occurrence of bad debt in our midstream and intrastate transportation and storage segments was not significant at the end of the 2007 and 2006 fiscal years; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage segments was not deemed necessary. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. There was $975 and $0 in bad debt expense recorded during the years ended August 31, 2006 and 2005, respectively, in the midstream and intrastate transportation and storage segments. For the year ended August 31, 2007, $780 was recovered that had been previously written off as bad debt expense.

Transwestern has a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact Transwestern s overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral to Transwestern. Transwestern sought additional assurances from customers due to credit concerns, and held aggregate prepayments of $598 at August 31, 2007, which are recorded in customer advances and deposits in the consolidated balance sheets. Transwestern s management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Transwestern establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. Transwestern considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectibility. For the period from acquisition to August 31, 2007, $18 was recovered that had been previously written off as bad debt expense related to Transwestern.

HOLP and Titan grant credit to their customers for the purchase of propane and propane-related products. Included in accounts receivable are trade accounts receivable arising from HOLP s retail and wholesale propane and Titan s retail propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane operations are recorded as amounts are billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the retail and wholesale propane segments is based on management s assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

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We enter into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

Accounts receivable consisted of the following:

	August 31, 2007	August 31, 2006
Accounts receivable midstream and intrastate transportation and storage	$ 529,655	$ 570,569
Accounts receivable interstate transportation	20,193	
Accounts receivable propane	93,429	108,976
Less allowance for doubtful accounts	(5,601)	(4,000)
Total, net	$ 637,676	$ 675,545

The activity in the allowance for doubtful accounts for the propane operations consisted of the following:

	August 31, 2007	August 31, 2006	August 31, 2005
Balance, beginning of the period	$ 4,000	$ 4,076	$ 1,667
Provision for loss on accounts receivable	4,229	1,723	5,523
Accounts receivable written off, net of recoveries	(2,628)	(1,799)	(3,114)
Balance, end of period	$ 5,601	$ 4,000	$ 4,076

The Titan accounts receivable as of June 1, 2006 were established at estimated fair value in connection with the Titan acquisition. The Transwestern accounts receivable as of December 1, 2006 were established at estimated fair value in connection with the Transwestern acquisition.

Inventories

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	August 31, 2007	August 31, 2006
Natural gas, propane and other NGLs	$ 174,164	$ 371,430
Appliances, parts and fittings and other	18,112	15,710
Total inventories	$ 192,276	$ 387,140

Exchanges

The midstream and intrastate transportation and storage segments exchanges consist of natural gas and NGL delivery imbalances with others. These amounts, which are valued at market prices, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. Management believes market value approximates cost.

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The interstate segment s natural gas imbalances occur as a result of differences in volumes of gas received and delivered. Transwestern records natural gas imbalance, in-kind receivables and payables at the dollar weighted composite average of all current month gas transactions and dollar valued imbalances are recorded at contractual prices.

Property, Plant and Equipment

Property, plant and equipment is stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated economic or Federal Energy Regulatory Commission (FERC) mandated lives of the assets. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the installation of company-owned propane tanks and construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural 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 our results of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of long-lived assets was required during the periods presented.

An accrual of allowance for funds used during construction (AFUDC) is a utility accounting practice calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC has been segregated into two component parts borrowed funds and equity funds. The allowance for borrowed and equity funds used during construction totaled $3,600 for the year ended August 31, 2007.

Components and useful lives of property, plant and equipment were as follows:

	August 31, 2007	August 31, 2006
Land and improvements	$ 63,997	$ 63,220
Buildings and improvements (10 to 30 years)	111,727	66,739
Pipelines and equipment (10 to 80 years)	3,271,993	1,757,103
Natural gas storage (40 years)	91,652	91,177
Bulk storage, equipment and facilities (3 to 30 years)	457,581	108,834
Tanks and other equipment (5 to 30 years)	509,095	472,944
Vehicles (5 to 10 years)	156,128	120,710
Right of way (20 to 80 years)	212,600	104,650
Furniture and fixtures (3 to 10 years)	24,465	16,283
Linepack	40,967	24,821
Pad Gas	55,482	57,327
Other (5 to 10 years)	85,240	27,395
	5,080,927	2,911,203
Less Accumulated depreciation	(402,128)	(242,137)
	4,678,799	2,669,066
Plus Construction work-in-process	869,584	644,583
Property, plant and equipment, net	$ 5,548,383	$ 3,313,649

Capitalized interest is included for pipeline construction projects. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. A total of $22,979, $12,605 and $191 of interest was capitalized for pipeline construction projects for the years ended August 31, 2007, 2006 and 2005, respectively (excluding AFUDC as discussed above).

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Depreciation expense for the periods is as follows:

Year Ended August 31,		
2007	2006	2005
$ 163,630	$ 107,148	$ 83,827

Asset Retirement Obligation

We account for our asset retirement obligations in accordance with Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* (SFAS 143) and FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, an entity would recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows. FIN 47 clarified that the term conditional asset retirement obligation , as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement of the obligation are uncertain. These conditional obligations were not previously addressed by SFAS 143. FIN 47 requires us to accrue the fair value of a liability for the conditional asset retirement obligation when incurred generally upon acquisition, construction or development and/or through the normal operation of the asset. Uncertainty about the timing and/or method of settlement of a conditional asset retirement should be factored into the measurement of the liability when a range of scenarios can be determined. FIN 47 clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

We have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates, and the credit-adjusted risk-free interest rates. However, management is not able to reasonably determine the fair value of the asset retirement obligations as of August 31, 2007 or August 31, 2006 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Advances to and Investment in Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we have a 20% to 50% ownership and exercise significant influences over, but do not control, the investee s operating and financial policies.

In December 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of the Midcontinent Express Pipeline (MEP). The approximately 500-mile interstate natural gas pipeline, that will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco s interstate natural gas pipeline in Butler, Alabama, will have an initial capacity of 1.4 Bcf per day and is expected to cost approximately $1,300,000 to construct. Pending necessary regulatory approvals, the pipeline project is expected to be in service by the second calendar quarter of 2009. MEP has prearranged binding commitments from multiple shippers for 800,000 dekatherms per day which includes a binding commitment from Chesapeake Energy Marketing, Inc., an affiliate of Chesapeake Energy Corporation, for 500,000 dekatherms per day. MEP has executed a firm capacity lease agreement for up to 500,000 dekatherms per day of capacity on the Oklahoma intrastate pipeline system of Enogex, a subsidiary of OGE Energy, to provide transportation capacity from various locations in Oklahoma into and through MEP. The new pipeline will also interconnect with Natural Gas Pipeline Company of America, a wholly-owned subsidiary of Knight, Inc. (formerly known as Kinder Morgan, Inc.), and with our Texoma pipeline near Paris, Texas. We account for our investment in MEP using the equity method of accounting.

The Partnership previously owned a 50% ownership interest in MidTexas Pipeline Company (MidTexas), a Texas general partnership, which owns approximately 139 miles of transportation pipeline that connects various

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receipt points in south Texas to delivery points at the Katy Hub. Effective February 28, 2007 MidTexas was dissolved and each partner was assigned its 50% undivided interest in the pipeline (a non-cash transaction). As a result of the dissolution and now owning an undivided interest, we control the marketing and bear the risk of ownership. As a result, we ceased the use of equity accounting at February 28, 2007 and began applying proportionate consolidation prospectively for our interest in the MidTexas pipeline.

Goodwill

Goodwill is associated with acquisitions made for our midstream, intrastate transportation and storage, interstate transportation, and retail propane segments. Substantially all of the $718,429 balance in goodwill is expected to be tax deductible. Goodwill is tested for impairment annually at August 31, in accordance with Statement of Accounting Standards No. 142, *Goodwill and Other Intangible Assets,* (SFAS 142). Based on the annual impairment tests performed in the fourth fiscal quarter, there was no impairment as of August 31, 2007, 2006 or 2005. The changes in the carrying amount of goodwill for the years ended August 31, 2007 and 2006 were as follows:

	Midstream	Intrastate Transportation and Storage	Interstate Transportation	Retail Propane	Total
Balance, August 31, 2005	$ 13,409	$ 10,327	$	$ 300,283	$ 324,019
Goodwill acquired				280,390	280,390
Balance, August 31, 2006	13,409	10,327		580,673	604,409
Purchase accounting adjustments				4,347	4,347
Goodwill acquired			107,550	4,167	111,717
Sale of operations				(2,044)	(2,044)
Balance, August 31, 2007	$ 13,409	$ 10,327	$ 107,550	$ 587,143	$ 718,429

The purchase price allocations for the Transwestern and other fiscal 2007 acquisitions (see Note 3) are preliminary. The final assessment of value and allocations for the fiscal 2007 acquisitions are expected to be completed by the first quarter of fiscal year 2008, and amounts allocated to goodwill may change. There is no guarantee that the preliminary allocation will not change.

The final Titan purchase allocation was made during the third quarter of fiscal 2007. The final allocation adjustments were not significant.

Intangibles and Other Assets

Intangibles and other long-term assets are stated at cost net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other long-term assets were as follows:

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	August 31, 2007		August 31, 2006	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 32,561	$ (17,669)	$ 31,593	$ (13,012)
Customer lists (3 to 15 years)	130,190	(22,501)	87,480	(11,640)
Contract rights (6 to 15 years)	23,015	(1,218)		
Consulting agreements (2 to 7 years)			132	(122)
Other (10 years)	2,677	(1,203)	2,677	(422)
Total amortizable intangible assets	188,443	(42,591)	121,882	(25,196)
Non-amortizable assets Trademarks	65,885		64,842	
Total intangible assets	254,328	(42,591)	186,724	(25,196)
Other long-term assets:				
Financing costs (3 to 15 years)	42,248	(8,868)	20,128	(4,441)
Regulatory assets	69,957			
Other	28,734		14,400	
Total intangibles and other long-term assets	$ 395,267	$ (51,459)	$ 221,252	$ (29,637)

Aggregate amortization expense of intangible assets is as follows:

	Year Ended August 31,		
	2007	2006	2005
Reported in depreciation and amortization	$ 15,532	$ 10,267	$ 9,443
Reported in interest expense	$ 4,502	$ 2,550	$ 3,923

The estimated aggregate amortization expense for the next five fiscal years is $23,610 for 2008; $22,769 for 2009; $21,369 for 2010; $20,295 for 2011; and $18,258 for 2012.

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, in accordance with Statement of Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually at August 31, or more frequently if circumstances dictate, in accordance with SFAS 144. No impairment of intangible assets was required for the years ended August 31, 2007, 2006 or 2005.

Customer Advances and Deposits

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit. Advances and deposits received from customers were $81,919 and $108,836 as of August 31, 2007 and 2006, respectively.

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Accrued and Other Current Liabilities

Accrued and other current liabilities consist of the following:

	August 31, 2007	August 31, 2006
Capital expenditures	$ 43,498	$ 38,002
Operating expenses	12,439	16,839
Litigation, environmental and other contingencies	35,707	34,823
Interest	29,828	13,956
Taxes other than income taxes	42,957	33,261
Other	27,656	23,817
Total accrued and other current liabilities	$ 192,085	$ 160,698

Fair Value of Financial Instruments

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at August 31, 2007 was $3,622,550 and $3,674,008, respectively. At August 31, 2006 the aggregate fair value and carrying amount of long-term debt was $2,589,918 and $2,629,702, respectively.

Shipping and Handling Costs

In accordance with EITF No. 00-10, *Accounting for Shipping and Handling Fees and Costs,* we have classified $109,412, $108,409 and $89,030 from producer payments for natural gas, compression and treating, which can be considered handling costs, as revenue for the years ended August 31, 2007, 2006 and 2005, respectively. Shipping and handling costs related to fuel sold are included in cost of sales. The remaining costs of approximately $58,583, $69,647 and $50,137 included in operating expenses reflect the cost of fuel consumed for compression and treating for the years ended August 31, 2007, 2006 and 2005, respectively. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts, and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs, and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis in cost of sales. The net amount of such taxes is not significant.

Income Taxes

Energy Transfer Partners, L.P. is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under the Partnership Agreement.

Our partnership will be considered to have terminated for federal income tax purposes if transfers of units within a 12-month period constitute the sale or exchange of 50% or more of our capital and profit interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of our capital and profits interests within the prior 12-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

Based on the information currently available to us, we believe that we exceeded the 50% threshold on May 7, 2007, and, as a result, we have determined that our partnership has terminated for federal tax income purposes on that date. This termination does not affect our classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income for federal income tax purposes. This termination will require us to close our taxable year, make new elections as to various tax matters and reset the depreciation schedule for our depreciable assets for federal income tax purposes. The resetting of our depreciation schedule will result in a deferral of the depreciation deductions allowable in computing the taxable income allocated to our Unitholders. However, certain elections we will make in connection with this tax termination will allow us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of our Unitholders, which deductions had not previously been utilized in computing taxable income allocable to our Unitholders.

As a result of the tax termination discussed above, we elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our subsidiary, HHI, which owns our Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of our common units. The amount of such goodwill accumulated as of the date of our acquisition of HHI (approximately $158,000) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. We account for HHI using the treasury stock method due to its ownership of our Class E units. Due to the accounting rules outlined in SFAS 109 and related Interpretations, we account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of our HHI purchase price allocation, which effectively results in a charge to our common equity and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the year ended August 31, 2007, this resulted in a current tax expense and deferred tax benefit (with a corresponding charge to common equity as an adjustment of the purchase price allocation) of approximately $1,200. As of August 31, 2007, the amount of tax goodwill to be amortized over the next 15 years for which HHI will receive a remedial income allocation is approximately $155,000.

As a limited partnership we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the periods ended August 31, 2007, 2006 and 2005, our non-qualifying income did not, or was not expected to, exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109). Under SFAS 109, deferred income taxes are recorded based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

Accounting for Derivative Instruments and Hedging Activities

We have established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. We apply Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) as amended to account for our derivative financial instruments. This statement requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at fair value. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment. For further discussion and detail of our derivative instruments and/or hedging activities see Note 10 Price Risk Management Assets and Liabilities .

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

We are exposed to market risk for changes in interest rates related to our bank credit facilities. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not cash flow hedges are classified in other income beginning in fiscal 2007. Prior to fiscal 2007, such gains or losses were reported in interest expense. See Note 10 for additional information related to interest rate derivatives.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flow from operating activities, in the same category as the cash flows from the items being hedged.

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, the Partnership Agreement of Energy Transfer Partners, L.P. (the Partnership Agreement) specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 6). Normal allocations according to percentage interests are made after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner.

New Accounting Standards

FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109*, (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. We adopted this statement on September 1, 2007. We are continuing to evaluate the impact of FIN 48, but at this time we believe that the adoption of FIN 48 will not have a material effect on our consolidated financial statements.

FASB Staff Position No. EITF 00-19-2, *Accounting for Registration Payment Arrangements* (FSP 00-19-2). FSP 00-19-2, issued in December 2006, provides guidance related to the accounting for registration payment arrangements. FSP 00-19-2 specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate arrangement or included as a provision of a financial instrument or arrangement, should be separately recognized and measured in accordance with FASB No. 5, *Accounting for Contingencies* (SFAS No. 5). FSP 00-19-2 requires that if the transfer of consideration under a registration payment arrangement is probable and can be reasonably estimated at inception, the contingent liability under such arrangement shall be included in the allocation of proceeds from the related financing transaction using the measurement guidance in SFAS No. 5. We adopted this Staff Position on September 1, 2007 and the impact was not significant.

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SFAS No. 154, *Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3* (SFAS 154). 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. Management adopted the provisions of SFAS 154 on September 1, 2006, with no material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 157, *Fair Value Measurement*, (SFAS 157). This standard provides guidance for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our calendar year beginning January 1, 2008 (see Note 16).

SFAS Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of SFAS Statements No. 87, 88, 106 and 132(R)*, (SFAS 158). Issued in September 2006, this statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multi-employer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. We adopted the recognition and disclosure provisions of SFAS 158 on December 1, 2006 in connection with our acquisition of Transwestern, the effect of which was not material. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. Management does not believe the adoption of the measurement provisions of this statement will have a material impact on our financial statements. We plan to adopt the measurement provisions of this statement when required during our calendar year beginning January 1, 2008 (see Note 16).

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*, (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment applies to all entities with available-for-sale and trading securities. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes the choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (discussed above). We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our calendar year beginning January 1, 2008 (see Note 16).

SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). In September 2006, the Securities and Exchange Commission (SEC) provided guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 establishes a dual

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approach that requires quantification of financial statement errors based on the effects of the error on each of the company s financial statements and the related financial statement disclosures. SAB 108 is effective for fiscal years ending after November 15, 2006. We adopted SAB 108 on August 31, 2007. The adoption did not have a material impact on our consolidated financial statements.

4. NET INCOME PER LIMITED PARTNER UNIT:

Our net income for partners capital and income statement presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the Incentive Distribution Rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. Basic net income per limited partner unit, however, is computed in accordance with EITF Issue No. 03-6, *Participating Securities and the Two-Class method under FASB Statement No. 128* (EITF 03-6), by dividing limited partners interest in net income by the weighted average number of limited partner units outstanding (excluding treasury units). 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 (see table below) and requires a separate computation for each quarter and year-to-date. For such periods, an increased amount of net income is allocated to the General Partner for the additional proforma priority income attributable to the application of EITF 03-6. The General Partner is entitled to receive incentive distributions if the amount we distribute to our limited partners with respect to any quarter exceeds levels specified in the Partnership Agreement. Diluted net income per limited partner unit is computed by dividing net income available to limited partners, after considering the General Partner s interest, by the weighted average number of limited partner units outstanding and the effect of non-vested restricted units (Unit Grants) granted under the Amended and Restated 2004 Unit Plan and predecessor plan computed using the treasury stock method.

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A reconciliation of net income and weighted average units used in computing basic and diluted earnings per unit is as follows:

	Years Ended August 31,		
	2007	2006	2005
Net income	$ 676,139	$ 515,852	$ 349,350
Adjustments:			
General Partner s equity ownership	(13,523)	(10,172)	(6,987)
General Partner s incentive distributions	(222,353)	(108,813)	(38,455)
Limited Partner s interest in net income	440,263	396,867	303,908
Additional earnings allocation to General Partner		(48,781)	(49,462)
Less earnings allocated to Class C Units as a result of the SCANA settlement (a)		(3,599)	
Net income available to limited partners	$ 440,263	$ 344,487	$ 254,446
Weighted average limited partner units basic	132,618,053	109,036,265	97,646,351
Limited Partners basic income per unit from continuing operations	$ 3.32	$ 3.16	$ 1.51
Limited Partners basic income per unit from discontinued operations			1.10
Basic net income per limited partner unit	$ 3.32	$ 3.16	$ 2.61
Weighted average limited partner units	132,618,053	109,036,265	97,646,351
Dilutive effect of Unit Grants	259,099	298,513	184,666
Weighted average limited partner units, assuming dilutive effect of Unit Grants	132,877,152	109,334,778	97,831,017
Limited Partners diluted income per unit from continuing operations	$ 3.31	$ 3.15	$ 1.50
Limited Partners diluted income per unit from discontinued operations			1.10
Diluted net income per limited partner unit	$ 3.31	$ 3.15	$ 2.60

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(a) As a result of the SCANA settlement discussed in Notes 6 and 9, we collected a settlement of $7,700 which is net of $3,300 of attorney fees. We retained $502 for litigation expenses previously incurred. The remaining $7,198 was allocated $3,599 to the Common and Class F Limited Partner Units and $3,599 as a special one-time distribution to the holder of our Class C Units for that amount normally allocated to our General Partner. The Limited Partner s share of available net income has been reduced accordingly.

5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	August 31, 2007	August 31, 2006	Maturities
ETP Senior Notes:			
2006 6.125% Senior Notes, net of discount of $331 and $0, respectively.	$ 399,669	$	One payment of $400,000 due February 15, 2017. Interest is paid semi-annually.
2006 6.625% Senior Notes, net of discount of $2,240 and $0, respectively.	397,760		One payment of $400,000 due October 15, 2036. Interest is paid semi-annually.
2005 5.95% Senior Notes, net of discount of $1,798 and $1,985, respectively.	748,202	748,015	One payment of $750,000 due February 1, 2015. Interest is paid semi-annually.
2005 5.65% Senior Notes, net of discount of $306 and $358, respectively.	399,694	399,642	One payment of $400,000 due August 1, 2012. Interest is paid semi-annually.

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Transwestern Senior Unsecured Notes:			
Notes payable assumed in connection with the Transwestern acquisition on December 1, 2006:			
5.39% Senior Unsecured Series Notes, including premium of $4,270	92,270		One payment due November 17, 2014. Interest is paid semi-annually.
5.54% Senior Unsecured Series Notes, net of discount of $5,030	119,970		One payment due November 17, 2016. Interest is paid semi-annually.
5.64% Senior Unsecured Series Notes	82,000		One payment due May 24, 2017. Interest is paid semi-annually.
5.89% Senior Unsecured Series Notes	150,000		One payment due May 24, 2022. Interest is paid semi-annually.
6.16% Senior Unsecured Series Notes	75,000		One payment due May 24, 2037. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
1996 8.55% Senior Secured Notes	48,000	60,000	Annual payments of $12,000 due each June 30th through 2011. Interest is paid semi-annually.
1997 Medium Term Note Program:			
7.17% Series A Senior Secured Notes	7,200	9,600	Annual payments of $2,400 due each November 19th through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	12,000	14,000	Annual payments of $2,000 due each November 19th through 2012. Interest is paid semi-annually.
6.50% Series C Senior Secured Notes		357	Paid and retired in March, 2007.
2000 and 2001 Senior Secured Promissory Notes:		3,200	Paid and retired in August, 2007.
8.47% Series A Senior Secured Notes			
8.55% Series B Senior Secured Notes	13,714	18,286	Annual payments of $4,571 due each August 15th through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	15,500	21,250	Annual payments of $4,000 due August 15, 2008, and $5,750 due each August 15, 2009 and 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	58,000	58,000	Annual payments of $12,450 due August 15, 2008 and 2009, $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	7,000	7,000	Annual payments of $1,000 due each August 15, 2009 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.21% Series G Senior Secured Notes	3,800	7,600	Annual payments of $3,800 due each May 15th through 2008. Interest is paid quarterly.

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7.89% Series H Senior Secured Notes	6,545	7,273	Annual payments of $727 due each May 15th through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment of $16,000 due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility (including Swingline loan option)	969,433	1,162,624	Available through June 2012 see terms below under Revolving Credit Facilities .
ETP $250,000 Revolving Credit Facility		20,000	Paid in October 2006.
HOLP Fourth Amended and Restated Senior Revolving Credit Facility		20,000	Available through June 30, 2011 - see terms below under Revolving Credit Facilities .
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 7.85 % and 7.56% for the years ended August 31, 2007 and 2006, respectively	10,537	14,204	Due in installments through 2014.
Other	1,714	2,651	Due in installments through 2024.
	3,674,008	2,629,702	
Current maturities of long-term debt	(47,031)	(40,578)	
	$ 3,626,977	$ 2,589,124	

Future maturities of long-term debt for each of the next five fiscal years and thereafter are as follows:

2008	$ 47,031
2009	44,172
2010	41,712
2011	1,002,385
2012	20,941
Thereafter	2,517,767
	$ 3,674,008

Registration Statement

During fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register up to $1,500,000 aggregate offering price of a combination of our limited partner interests and debt securities. On October 23, 2006, we closed the issuance, under our $1,500,000 S-3 Registration Statement and received net proceeds of approximately $791,000 (see ETP Senior Notes below). The notes are unsecured senior obligations of the Partnership.

Registered Exchange Offer

During fiscal year 2006, we filed a registered exchange offer to exchange newly issued 5.65% Senior Notes due 2012 (the 2012 Notes) that were registered under the Securities Act of 1933 (the New Notes), for a like amount of outstanding 5.65% Senior Notes due 2012, which had not been registered under the Securities Act (the Old Notes). The exchange offer closed on March 31, 2006. All $400,000 of the Old Notes were tendered pursuant to the exchange offer and were replaced with a like amount of New Notes. The sole purpose of the exchange offer was to fulfill our obligations under the registration rights agreement entered into in connection with our sale of the Old Notes on July 29, 2005. The New Notes issued pursuant to the exchange offer have substantially identical terms to the Old Notes.

ETP Senior Notes

On October 23, 2006, ETP issued a total of $800,000 aggregate principal amount of Senior Notes comprised of $400,000 of 6.125% Senior Notes due 2017 and $400,000 of 6.625% Senior Notes due 2036 (collectively, the ETP Senior Notes). The Partnership used the proceeds of approximately $791,000 (net of bond discounts of $2,612 and financing costs of $6,050) from the issuance of the ETP Senior Notes to repay borrowings and accrued interest outstanding under the Revolving Credit Facility, to pay expenses associated with the offering and for general partnership purposes. Interest on the ETP Senior Notes is due semiannually. The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. These ETP Senior Notes have been registered under the Securities Act pursuant to our S-3 Registration Statement which provides for the sale of a combination of units and debt totaling $1,500,000.

In connection with the Partnership entering into the credit agreement for the ETP Credit Facility in July 2007 as described in more detail below, all guarantees by ETC OLP, Titan and all of their direct and indirect wholly-owned subsidiaries for the ETP Senior Notes were released and discharged. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern Assumed Long-Term Debt and Senior Unsecured Notes

On December 1, 2006 we assumed the following long-term debt in connection with the Transwestern acquisition:

5.39% Notes due November 17, 2014	$ 270,000
5.54% Notes due November 17, 2016	250,000
Total long-term debt outstanding	520,000
Unamortized debt discount	(623)
Total long-term debt assumed	$ 519,377

No principal payments are required under any of the Transwestern debt agreements prior to their respective maturity dates. Due to a change in control provision in Transwestern s debt agreements, Transwestern was required to pre-pay $292,000 and $15,000 in February and March 2007, respectively. These payments were initially financed with borrowings from ETP s previously existing revolving credit facility.

In May 2007, Transwestern issued a total of $307,000 aggregate principal amount of Senior Unsecured Series Notes (Transwestern Series Notes) comprised of the following:

Principal	Interest Rate	Maturity Date
$ 82,000	5.64%	May 24, 2017
150,000	5.89%	May 24, 2022
75,000	6.16%	May 24, 2037

The Partnership used $295,000 of the proceeds received to repay borrowings and accrued interest outstanding under its previously existing revolving credit facility and $12,000 for general partnership purposes. Interest is payable semi-annually, and the Transwestern Series Notes rank pari passu with Transwestern s other unsecured debt. The Transwestern Series Notes are prepayable at any time in whole or pro rata in part, subject to a premium or upon a change of control event, as defined.

Transwestern s credit agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and require certain debt to capitalization ratios.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes. In addition to the stated interest rate for the HOLP Notes, we are required to pay an additional 1% per annum on the outstanding balance of the HOLP Notes at such time as the HOLP Notes are not rated investment grade status or higher. As of August 31, 2007 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

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Revolving Credit Facilities

ETP Facilities

On July 20, 2007, we entered into the ETP Credit Facility with Wachovia Bank, National Association, as administrative agent and Bank of America, N.A., as syndication agent, and certain other agents and lenders. The ETP Credit Facility replaced our previously existing $1,500,000 revolving credit facility, and all outstanding borrowings and letters of credit under our previously existing revolving credit facility were replaced by borrowings and letters of credit under the ETP Credit Facility. The $1,500,000 prior credit facility was then terminated. The ETP Credit Facility provides for $2,000,000 of revolving credit capacity that is expandable to $3,000,000 at our option (subject to the approval of the administrative agent under the Amended and Restated Credit Agreement, which approval is not to be unreasonably withheld). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments under the ETP Credit Facility). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The ETP Credit Facility has a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2,000,000 unless expanded to $3,000,000) less the sum of all outstanding revolving credit loans and the letter of credit obligation and (ii) the swingline commitment. The aggregate amount of swingline loans in any borrowing shall not be subject to a minimum amount or increment. The indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership s and certain of the Partnership s subsidiaries ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions during certain Defaults and during any Event of Default;
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates;
- enter into restrictive agreements; and

enter into speculative hedging contracts.

This credit agreement also contains a financial covenant that provides that on each date the Partnership makes a Distribution, the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1, with a permitted increase to 5.5 to 1 during a specified Acquisition Period (as such terms are used in the credit agreement).

As of August 31, 2007, there was a balance of $969,433 in revolving credit loans (including $107,433 in Swingline loans) and $57,256 in letters of credit. The weighted average interest rate on the total amount outstanding at August 31, 2007, was 6.01%. The total amount available under the new credit facility, as of August 31, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $973,311. The indebtedness under the new credit facility is unsecured and not guaranteed by any of the Partnership s subsidiaries. In connection with entering into the new credit agreement, all guarantees by ETC OLP, Titan and their direct and indirect wholly-owned subsidiaries of the ETP Senior Notes were released and discharged. The indebtedness under the new credit facility has equal rights to holders of our other current and future unsecured debt.

On September 25, 2006, we exercised the accordion feature of the previously existing revolving credit facility and expanded the amount of the facility from $1,300,000 to $1,500,000. Amounts borrowed under the previously existing revolving credit facility bore interest at a rate based on either a Eurodollar rate or a prime rate. The previously existing revolving credit facility had a swingline loan option with a maximum borrowing of $75,000 at a daily rate based on LIBOR. The commitment fee payable on the unused portion of the facility varies based on our credit rating and the maximum fee was 0.175%. The previously existing revolving credit facility was fully and unconditionally guaranteed by ETC OLP and Titan and all of their direct and indirect wholly-owned subsidiaries of ETP. The previously existing revolving credit facility was unsecured and had equal rights to holders of our other current and future unsecured debt.

On October 18, 2006 we paid and retired a $250,000 unsecured revolving credit facility which matured under its terms on December 1, 2006. Amounts borrowed under this facility bore interest at a rate based on either a Eurodollar rate or a base rate. The maximum commitment fee payable on the unused portion of the facility was 0.25%. The $250,000 revolving credit facility was fully and unconditionally guaranteed by ETC OLP and all of the direct and indirect wholly-owned subsidiaries of ETC OLP.

HOLP Facilities

Effective August 31, 2006, HOLP entered into the Fourth Amended and Restated Credit Agreement, a $75,000 Senior Revolving Facility available through June 30, 2011 (the HOLP Facility), which may be expanded to $150,000. The HOLP Facility has a swingline loan option with a maximum borrowing of $10,000 at a prime rate. Amounts borrowed under the HOLP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility (total book value as of August 31, 2007 of approximately $1,200,000). There was no balance outstanding on the HOLP Facility as of August 31, 2007. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Facility. There were outstanding letters of credit under the HOLP Facility of $1,002 at August 31, 2007. The sum of the loans made under the HOLP Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the maximum amount of the HOLP Facility.

Covenants Related to Our Credit Agreements

The agreements for each of the Senior Notes, Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the revolving credit facilities contain customary restrictive covenants applicable to ETP and the Operating Partnerships, including the achievement of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The most restrictive of these covenants require us to maintain ratios of Consolidated Funded Indebtedness to Consolidated EBITDA, as defined in the agreements, for the specified four fiscal quarter period of not greater than 5.0 to 1.0, with a permitted increase to 5.5 to 1.0 during a specified Acquisition Period (these terms are defined in the credit agreement related to the ETP Credit Facility), Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the credit agreement related to the ETP Credit Facility and the note agreements related to the HOLP Notes) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the credit agreement related to the ETP Credit Facility and the note agreements related to the HOLP Notes) of not less than 2.25 to 1. The Consolidated EBITDA used to determine these ratios is calculated in accordance with these debt agreements. For purposes of calculating these ratios, Consolidated EBITDA is based upon our EBITDA, as adjusted for the most recent four quarterly periods, and modified to give pro forma effect for acquisitions and divestitures 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. These debt agreements also provide that the Operating Partnerships may declare, make, or incur a liability to make, restricted payments 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 with respect to the immediately preceding quarter; (b) no default or event of default exists before such restricted payments; and (c) each Operating Partnership s restricted payment is not greater than the product of each Operating Partnership s Percentage of Aggregate Available Cash multiplied by the Aggregate Partner Obligations (as these terms are similarly defined in the bank credit facilities and the Note Agreements). The note agreements related to the HOLP Notes further provide that HOLP s Available Cash is required to reflect a reserve equal to 50% of the interest to be

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paid on the notes and 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, 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 our bank credit facilities and the Note Agreements could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Partnerships ability to incur additional debt and/or our ability to pay distributions. We are required to measure these financial tests and covenants quarterly. We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of August 31, 2007.

6. PARTNERS CAPITAL AND UNIT-BASED COMPENSATION PLANS:

Registration Statement

During fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1,000,000 aggregate offering price of Common Units representing our Limited Partner interests. Through August 31, 2007, we have not made any sales under this Registration Statement.

On August 9, 2006 we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1,500,000 aggregate offering price of Common Units representing Limited Partner interests of Energy Transfer Partners, L.P., and debt securities. On October 23, 2006, we closed the issuance, under our $1.5 billion S-3 registration statement, of $400,000 of 6.125% Senior Notes due 2017 and $400,000 of 6.625% Senior Notes due 2036. We used the net proceeds of approximately $791,000 from the issuance of the Notes to repay borrowings and accrued interest under our Revolving Credit Facility, to pay expenses associated with the offering and for general partnership purposes.

Limited Partner Units

Limited Partner interests are represented by Common, Class E and (prior to May 1, 2007) Class G Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of August 31, 2007, there were issued and outstanding 136,981,221 Common Units representing an aggregate 98% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

On March 15, 2005, a two-for-one split for each Class of our Limited Partner Units was effected which entitled Unitholders of record at the close of business on February 28, 2005 to receive one additional Partnership unit for each Partnership unit owned on that date. The unit split required retroactive restatement of all historical unit and per unit data in the consolidated financial statements. The effect of the split was to double the number of all outstanding Limited Partner Units and to reduce by half the minimum quarterly per unit distribution and the targeted distribution levels. All references to Limited Partner Units and per unit information for fiscal year 2005 herein have been restated to reflect the effects of the two-for-one split.

No person is entitled to preemptive rights in respect of issuances of securities by us, except that ETP GP has the right to purchase sufficient partnership securities to maintain its General Partner equity interest in us.

Incentive Distribution Rights represent the contractual right to receive an increasing 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 has owned all of the Incentive Distribution Rights since July 14, 2006 when the Class C Units were retired.

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Common Units

The change in Common Units during the three year period ended August 31, 2007 is as follows:

	Number of Units		
	August 31, 2007	August 31, 2006	August 31, 2005
Balance, beginning of year	110,726,999	106,889,904	89,118,062
Issuance of Common Units			17,602,960
Issuance of Common Units in connection with certain acquisitions		99,955	120,550
Issuance of restricted Common Units	167,265	97,140	48,332
Issuance of Common Units to Energy Transfer Equity, LP		1,069,850	
Conversion of Class F Units to Common Units		2,570,150	
Conversion of Class G Units to Common Units	26,086,957		
Balance, end of year	136,981,221	110,726,999	106,889,904

Of the total restricted Common Units issued during fiscal 2007, 156,573 were employee awards under our 2004 Unit Plan (discussed below), 7,025 were Director Awards under our 2004 Unit Plan, and 3,667 were Director Awards under our Restricted Unit Plan which vested on September 1, 2006. As of August 31, 2007, there were no unvested awards remaining under the Restricted Unit Plan (terminated in June 2004). No additional grants have been, or will be, made under the Restricted Unit Plan.

Our Common Units are registered under the Securities Act of 1934 and are listed for trading on the New York Stock Exchange. 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 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 the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under Quarterly Distributions of Available Cash.

Fiscal Year 2007 Activity

On November 1, 2006, we issued 26,086,957 Class G Units to ETE for aggregate proceeds of $1,200,000 in order to fund a portion of the Transwestern Acquisition and to repay indebtedness we incurred in connection with the Titan acquisition. The Class G Units, a newly created class of our limited partner interests, were issued to ETE at a price of $46.00 per unit, based upon a market discount from the closing price of our Common Units on October 31, 2006 of $48.94. The terms of the Class G Units are described in more detail below. The Class G Units were issued to ETE pursuant to a customary agreement, and registration rights were granted to ETE.

Also during fiscal year 2007, we:

- issued 167,265 Common Units under our Restricted Unit Plan as discussed in Unit Based Compensation Plans below; and
- converted 26,086,957 Class G Units to Common Units (see details in *Class G Units* below).

Fiscal Year 2006 Activity

On February 6, 2006, pursuant to its General Partner authority, our General Partner amended our Amended and Restated Agreement of Limited Partnership to create a new class of limited partner interests titled Class F Units (the terms of the Class F Units are described in more detail below). On February 8, 2006, we sold and issued 1,069,850 Common Units (and 2,570,150 Class F Units) representing limited partner interests in the Partnership, to ETE in a private placement. ETE owns 100% of the 2% General Partner interests in ETP GP and 100% of the Incentive Distribution Rights in the Partnership (which it holds through its ownership interests in ETP GP). The price paid for each of the Common Units and Class F Units was equal to $36.37 per unit, the New York Stock Exchange closing price of the Partnership s Common Units on February 8, 2006. Of the aggregate proceeds of $132,387 from the sale, $75,000 was used to extinguish the HOLP Senior Revolving Acquisition Facility, to pay down the HOLP Senior Revolving Working Capital Facility, and for HOLP general operating purposes. The remaining proceeds of $57,387 were used to pay down existing debt on the ETP Revolving Credit Facility and for general Partnership operating purposes.

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Also during fiscal year 2006, we:

- issued 99,955 Common Units valued at $4,000 in connection with a propane acquisition to the former owners of such operations;

- issued 97,140 Common Units under our Restricted Unit Plan as discussed in Unit Based Compensation Plans below; and

- converted 2,570,150 Class F Units to Common Units (see details in *Class F Units* below).

Fiscal Year 2005 Activity

On January 26, 2005, we placed $350,000 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 unregistered Common Units for total consideration of $170,000, and we became obligated under a Units Purchase Agreement dated January 14, 2005 to issue an additional 6,666,666 Common Units for total consideration of $180,000. 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.

During fiscal year 2005, we also:

- completed the sale of 1,640,000 Common Units to a group of our executive managers including our President, Vice-President and General Counsel, and Vice-President-Corporate Development. The units were sold at a price of $31.95 per Common Unit, which represented a 6% discount to the closing Common Unit price on June 17, 2005. We believe the price received is comparable to the price that we would have received from an unaffiliated purchaser in a large block equity transaction. The transaction was approved by a committee of independent directors of the General Partner;

- completed the sale of 3,000,000 Common Units in a private sale to an institutional investor. The Common Units were issued pursuant to our effective shelf registration statement and we used the proceeds of $105,600 to retire a portion of the outstanding indebtedness on our revolving credit facility and to fund our capital expansion projects;

- issued 45,534 and 75,016 Common Units valued at $1,000 and $1,500, respectively, in connection with propane acquisitions to former owners of such companies; and

- issued 48,332 Common Units under our Restricted Unit Plan.

Class C Units

The change in Class C Units during the three year period ended August 31, 2007 is as follows:

	August 31, 2007	August 31, 2006	August 31, 2005
Balance, beginning of year		1,000,000	1,000,000
Retirement and cancellation of Class C Units		(1,000,000)	

Balance, end of year	1,000,000

The 1,000,000 Class C Units were issued to HHI in August 2000 in conjunction with the U.S. Propane transaction and the change of control of our General Partner in conversion of that portion of HHI s Incentive Distribution Rights that entitled it to receive any distribution attributable to the net amount we received in connection with the settlement, judgment, award or other final nonappealable resolution of specified litigation we filed prior to the transaction with U.S. Propane, referred to as the SCANA litigation. The Class C Units had a zero initial capital account balance and were distributed by HHI to its former stockholders in connection with the U.S. Propane transaction. On June 1, 2006, we received net settlement proceeds of $7,700 on all four of our claims with respect to the SCANA litigation (see Note 9).

All decisions of our General Partner relating to the SCANA litigation were determined by a special litigation committee consisting of one or more independent directors of our General Partner. On June 20, 2006, the special

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litigation committee approved the distribution of all litigation proceeds we received after deducting all costs and expenses we and our affiliates incurred in connection with the SCANA litigation and any cash reserves necessary or appropriate to provide for operating expenditures. Following this determination, the distributable proceeds were deemed to be Available Cash under the Partnership Agreement and were distributed on July 14, 2006 (as described below under Quarterly Distributions of Available Cash). Such distribution totaled $3,515, $3,599 and $83 to the Common Units, Class C Units and Class F Units ($0.0325 per Common and Class F Unit), respectively.

Upon making payment to the holder of the Class C Units, all 1,000,000 outstanding Class C Units were retired and canceled. The Class C Units did not have any rights to share in any of our assets or distributions upon dissolution and liquidation, except to the extent that any such distributions consisted of proceeds from the SCANA litigation to which the Class C Unitholders would have otherwise been entitled. The Class C Units did not have the privilege of conversion into any other unit and did not have any voting rights except to the extent provided by law, in which case each Class C Unit would be entitled to one vote.

The amount of cash distributions to which the Incentive Distribution Rights were entitled was not increased by the creation of the Class C Units; rather, the Class C Units were a mechanism for dividing the Incentive Distribution Rights to which HHI and its former stockholders would have been entitled.

Class E Units

There are 8,853,832 Class E Units outstanding that are reported as treasury units. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. Management plans to leave the Class E Units in the form described here indefinitely. In the event of our termination and liquidation, the Class E Units will be allocated 1% of any gain upon liquidation and will be allocated any loss upon liquidation to the same extent as Common Units. After the allocation of such amounts, the Class E Units will be entitled to the balance in their capital accounts, as adjusted for such termination and liquidation. The terms of the Class E Units were determined in order to provide us with the opportunity to minimize the impact of our ownership of Heritage Holdings, including the $57,449 in deferred tax liabilities of Heritage Holdings that were included in the purchase of Heritage Holdings. The Class E Units are treated as treasury stock for accounting purposes because they are owned by our wholly-owned subsidiary, Heritage Holdings. Due to the ownership of the Class E Units by this corporate subsidiary, the payment of distributions on the Class E Units will result in annual tax payments by Heritage Holdings at corporate federal income tax rates, which tax payments will reduce the amount of cash that would otherwise be available for distribution to us as the owner of Heritage Holdings. Because distributions on the Class E Units will be available to us as the owner of Heritage Holdings, those funds will be available, after payment of taxes, for general partnership purposes, including to satisfy working capital requirements, for the repayment of outstanding debt and to make distributions to the Unitholders. Because the Class E Units are not entitled to receive any allocation of Partnership income, gain, loss, deduction or credit that is attributable to our ownership of Heritage Holdings, such amounts will instead be allocated to the General Partner in accordance with its respective interest and the remainder to all Unitholders other than the holders of Class E Units pro rata. In the event that Partnership distributions exceed $1.41 per unit annually, all such amounts in excess thereof will be available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests.

Class F Units

The change in Class F Units during the three year period ended August 31, 2007 is as follows:

	August 31, 2007	August 31, 2006	August 31, 2005
Balance, beginning of year			
Issuance of Class F Units to Energy Transfer Equity, LP		2,570,150	
Conversion of Class F to Common Units		(2,570,150)	
Balance, end of year			

As discussed above, on February 8, 2006, we issued 2,570,150 Class F Units representing limited partnership interests in the Partnership to ETE in a private placement that is exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended. On August 15, 2006 our Common Unitholders approved a proposal to

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change the terms of the Class F Units and each Class F Unit converted to Common Units on a one-for-one basis. Prior to conversion of the Class F Units, the Class F Units shared in Partnership distributions and were entitled to all items of Partnership income, gain, loss, deduction and credit as if the Class F Units were Subordinated Units.

Class G Units

The change in Class G Units during the three year period ended August 31, 2007 is as follows:

	August 31, 2007	August 31, 2006	August 31, 2005
Balance, beginning of year			
Issuance of Class G Units to Energy Transfer Equity, LP	26,086,957		
Conversion of Class G to Common Units	(26,086,957)		
Balance, end of year			

As discussed above, on November 1, 2006, we issued 26,086,957 Class G Units to ETE for aggregate proceeds of $1,200,000. The terms of the Class G Units provided that they may be converted to Common Units on a one-for-one basis upon approval of a majority of the votes cast by the holders of our Common Units provided that the total votes cast by such holders represent a majority of the Common Units entitled to vote. The Class G Units were issued to ETE pursuant to a customary agreement, and registration rights were granted to ETE. On May 1, 2007, at a special meeting of the Common Unitholders, the Unitholders approved the conversion of Class G Units to Common Units and all of the outstanding Class G Units converted to Common Units on a one-for-one basis on such date.

Quarterly Distributions of Available Cash

The Partnership Agreement requires that we distribute all of our Available Cash to our Unitholders and our General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of Incentive Distribution Rights to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any of our fiscal quarters, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of our business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in our Partnership Agreement.

Our distributions from operating surplus for any quarter in an amount equal to 100% of Available Cash will generally be made as follows, subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of quarterly cash distributions are achieved ($0.275 per unit):

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 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 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 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.

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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 declared during the years ended August 31, 2007, 2006 and 2005 are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Fiscal Year 2007	July 2, 2007	July 16, 2007	$ 0.80625
	April 6, 2007	April 13, 2007	$ 0.78750
	January 4, 2007	January 15, 2007	$ 0.76875
	October 5, 2006	October 16, 2006	$ 0.75000
Fiscal Year 2006	June 30, 2006	July 14, 2006	$ 0.63750
	June 30, 2006 (1)	July 14, 2006	$ 0.03250
	March 24, 2006	April 14, 2006	$ 0.58750
	January 4, 2006	January 13, 2006	$ 0.55000
	September 30, 2005	October 14, 2005	$ 0.50000
Fiscal Year 2005	July 8, 2005	July 14, 2005	$ 0.48750
	March 16, 2005	April 14, 2005	$ 0.46250
	January 5, 2005	January 14, 2005	$ 0.43750
	October 7, 2004	October 15, 2004	$ 0.41250

(1) Special SCANA distribution see discussion in Class C Units above and Note 9 for further information.

On May 1, 2006, the Partnership Agreement was amended to permit the General Partner, pursuant to its General Partner authority, to declare the next quarterly distribution prior to the close of such quarter.

On September 25, 2007, we announced the declaration of a cash distribution for the fourth quarter ended August 31, 2007 of $0.825 per Common Unit, or $3.30 annually, an increase of $0.075 per Common Unit on an annualized basis. The distribution was paid on October 15, 2007 to Unitholders of record at the close of business on October 5, 2007.

The total amounts of distributions declared relating to the years ended August 31, 2007, 2006 and 2005 are as follows (all from Available Cash from our operating surplus):

	2007	2006	2005
Limited Partners			
Common Units	$ 366,180	$ 248,237	$ 173,802
Class C Units (1)		3,599	
Class F Units		3,232	
Class G Units	40,598		
General Partners			
2% Ownership	12,701	6,981	4,390
Incentive Distribution Rights	203,069	81,722	28,847
	$ 622,548	$ 343,771	$ 207,039

(1) Special SCANA distribution see Note 9.

Upon their conversion to Common Units, as discussed above, the Class F and G Units ceased to have the right to participate in distributions of available cash from operating surplus.

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Unit-Based Compensation Plans

We follow the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004) *Accounting for Stock-based Compensation* (SFAS 123R) for our unit-based compensation plans. Generally, the recipients of the stock grants are not entitled to receive any unit distributions during the required service period for vesting. Accordingly, as provided in SFAS 123R, the Partnership values the unit awards based on the per unit grant-date market value reduced by the present value of the distributions expected to be paid on the units during the requisite service period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected unit distributions.

We recognized compensation expense of $10,471, $7,038 and $1,608 for the years ended August 31, 2007, 2006 and 2005, respectively, related to unit-based compensation plans.

2004 Unit Plan

Our Amended and Restated 2004 Unit Award Plan (the 2004 Unit Plan) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers, and directors. Any awards that are forfeited or which expire for any reason or any units which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. Units to be delivered upon the vesting of awards granted under the 2004 Unit Plan may be (i) units acquired by us in the open market, (ii) units already owned by us or our General Partner, or (iii) units acquired by us or our General Partner directly from us, or any other person. We may issue units under the 2004 Unit Plan without registration under the federal securities law, in which case holders of these units would be subject to restrictions on their ability to sell these units, or we may issue units pursuant to a registration statement, in which case the holders of these units would not be subject to these restrictions. As of August 31, 2007, 997,807 ETP Common Units were available for future grants under the 2004 Unit Plan.

The 2004 Unit Plan is administered by the Compensation Committee of the Board of Directors of our General Partner (the Compensation Committee) and may be amended from time to time by the Board; provided however, that no amendment will be made without the approval of a majority of the Unitholders (i) if so required under the rules and regulations of the New York Stock Exchange or the Securities and Exchange Commission; (ii) that would extend the maximum period during which an award may be granted under the Plan; (iii) materially increase the cost of the Plan to the Partnership; or (iv) result in this Plan no longer satisfying the requirements of Rule 16b-3 of Section 16 of the Securities and Exchange Act of 1934. This Plan shall terminate no later than the 10th anniversary of its original effective date (June 23, 2014).

Employee Grants

The Compensation Committee, in its discretion, may from time to time grant awards to any employee, upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the 2004 Unit Plan. All outstanding awards shall fully vest into units upon any Change in Control as defined by the 2004 Unit Plan, or upon such terms as the Compensation Committee may require at the time the award is granted.

To date, substantially all of the awards granted to employees under the 2004 Unit Plan require the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award has been structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three year period. The performance criteria are generally based upon the total return (unit price appreciation plus cash distributions) to our Unitholders as compared to a group of publicly traded partnership peer companies. Compensation expense is recorded based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded. We have also granted a limited number of unit awards to employees that vest 20% per year over a five year period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. The issuance of Common Units pursuant to the 2004 Unit Plan is intended to serve as a means of incentive compensation, therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

We assumed a weighted average risk-free interest rate of 4.45%, 3.64% and 2.87% for the years ended August 31, 2007, 2006 and 2005, respectively, in estimating the present value of the future cash flows of the distributions

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during the vesting period on the measurement date of each employee grant. For the employee awards outstanding during the years ended August 31, 2007, 2006 and 2005, respectively, the grant-date average per unit cash distributions were estimated to be $5.50, $4.02 and $4.73, respectively. Upon vesting, ETP Common Units are issued.

The following table shows the activity of the awards granted for the years ended August 31, 2007, 2006 and 2005:

	Number of Units	Weighted Average Fair Value Per Unit
Awards granted during fiscal year 2005	273,200	$ 19.64
Awards vested during fiscal year 2005		
Awards forfeited during fiscal year 2005	(7,600)	21.10
Unvested awards as of August 31, 2005	265,600	19.60
Awards granted during fiscal year 2006	183,200	31.08
Awards vested during fiscal year 2006	(88,183)	21.65
Awards forfeited during fiscal year 2006	(2,867)	21.10
Unvested awards as of August 31, 2006	357,750	24.96
Awards granted during fiscal year 2007	458,200	43.75
Awards vested during fiscal year 2007	(156,573)	24.23
Awards forfeited during fiscal year 2007	(101,940)	34.35
Unvested awards as of August 31, 2007	557,437	39.08

The total expected compensation expense to be recognized related to the unvested employee awards as of August 31, 2007 is $5,679 for fiscal year 2008, $2,178 for fiscal year 2009, $369 for fiscal year 2010, $210 for fiscal year 2011, and $89 for fiscal year 2012.

On October 2, 2007 the Compensation Committee of our General Partner determined that based on our performance for the year ended August 31, 2007, of the 225,887 employee awards scheduled to vest on September 1, 2007, 25%, or 56,482 employee awards vested and 75%, or 169,405 awards were forfeited. The Compensation Committee of our General Partner also approved a special one-time grant of 158,080 employee awards which are not subject to performance objectives but are subject only to continued employment with us through the first anniversary of the grant date of October 2, 2007.

Director Grants

Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, the Partnership, or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of up to 2,000 ETP Common Units (the Initial Director s Grant). Commencing on September 1, 2004 and each September 1 thereafter that this Plan is in effect, each Director Participant who is in office on such September 1, shall automatically receive an award of Units equal to $25 ($15 prior to October 17, 2006) divided by the fair market value of a Common Unit on such date rounded to the nearest increment of ten Units (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of one third per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a change in control, as defined by the Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which have not yet vested on the date a Director Participant ceases to be a director shall vest on such terms as may be determined by the Compensation Committee.

We assumed a weighted average risk-free interest rate of 3.80%, 3.21% and 2.60% for the years ended August 31, 2007, 2006 and 2005, respectively, in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each Director Grant. For the Director Awards granted during the years ended August 31, 2007, 2006 and 2005, respectively, the grant-date average per unit cash distributions were estimated to be $4.95, $4.11, and $3.16, respectively.

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The following table shows the activity of the Director Awards granted for the years ended August 31, 2007, 2006 and 2005:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of August 31, 2004	12,000	$ 18.47
Annual Director s Grants awarded in fiscal year 2005	4,844	18.49
Awards vested during fiscal year 2005	(3,999)	19.92
Unvested awards as of August 31, 2005	12,845	18.03
Initial Director Grants awarded in fiscal year 2006	4,000	30.52
Annual Director Grants awarded in fiscal year 2006	2,460	33.23
Awards vested during fiscal year 2006	(2,624)	19.74
Awards forfeited during fiscal year 2006	(730)	32.98
Unvested awards as of August 31, 2006	15,951	22.54
Initial Director Grants awarded in fiscal year 2007		
Annual Director Grants awarded in fiscal year 2007	3,240	41.47
Awards vested during fiscal year 2007	(7,025)	22.45
Awards forfeited during fiscal year 2007		
Unvested awards as of August 31, 2007	12,166	$ 27.63

The total expected compensation expense to be recognized related to the unvested Director Awards as of August 31, 2007 is expected to be $60 for fiscal year 2008 and $14 for fiscal year 2009.

On October 17, 2006, the Compensation Committee recommended, following its receipt and review of an independent third-party compensation study, and the Board of Directors approved, an amendment to the 2004 Unit Plan to provide that Annual Director s Grants shall be equal to $25 divided by the fair market value of Common Units on that date. All other Annual Director s Grants shall be measured at September 1 of each year. On October 17, 2006, 3,240 Annual Director Grants were awarded.

On September 1, 2007, Annual Director Grants of 2,880 units were awarded and 5,220 Director Grants vested and Common Units were issued.

Long-Term Incentive Grants

The Compensation Committee may, from time to time, grant awards under the Plan to any executive officer or any employee it designates as a participant in accordance with general guidelines under the Plan. These guidelines include (i) options to purchase a specified number of units at a specified exercise price, which are clearly designated in the award as either an incentive stock option within the meaning of Section 422 of the Internal Revenue Code, or a non-qualifying stock option that is not intended to qualify as an incentive stock option under Section 422; (ii) Unit Appreciation Rights that specify the terms of the fair market value of the award on the date the unit appreciation right is exercised and the strike price; (iii) units; or (iv) any combination hereof. As of August 31, 2007, there have been no Long-Term Incentive Grants made under the Plan.

Restricted Unit Plan

Our General Partner, Energy Transfer Partners GP, L.P. (ETP GP) previously adopted the Amended and Restated Restricted Unit Plan dated August 10, 2000, amended February 4, 2002 as the Second Amended and Restated Restricted Unit Plan (the Restricted Unit Plan), for certain directors and key employees of ETP GP and its affiliates. The Restricted Unit Plan provided rights to acquire up to 292,000 Common Units of

ETP.

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Following the June 23, 2004 approval of the 2004 Unit Plan at the special meeting of the Unitholders, the Restricted Unit Plan was terminated (except for the obligation to issue Common Units at the time the 16,592 grants previously awarded vest), and no additional grants have been or will be made under the Restricted Unit Plan. Previously granted awards of 3,667, 5,000, and 4,333 vested and Common Units were issued during fiscal years 2007, 2006 and 2005, respectively.

Related Party Awards

During fiscal year 2007, a partnership, the general partner of which is owned and controlled by the President of our General Partner, awarded to certain new officers of ETP certain rights related to units of ETE previously issued by ETE to such officer. These rights include the economic benefits of ownership of these units based on a 5-year vesting schedule whereby the officer will vest in the units at a rate of 20% per year. None of the costs related to such awards are paid by ETP or ETE. Based on GAAP covering related party transactions and unit-based compensation arrangements, we are recognizing non-cash compensation expense over the vesting period based on the grant date market value of the ETE units awarded the ETP employees assuming no forfeitures. Awards granted for the fiscal year ended August 31, 2007 result in a total non-cash compensation expense of approximately $23,523 to be recognized over the related vesting period. For the year ended August 31, 2007, we recognized non-cash compensation expense of $5,191 as a result of these awards. As these units were outstanding prior to these awards, the awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE. We expect to recognize non-cash compensation expense as follows in future periods related to these awards:

Fiscal 2008	$ 8,505
Fiscal 2009	4,902
Fiscal 2010	2,919
Fiscal 2011	1,536
Fiscal 2012	471

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7. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended August 31,		
	2007	**2006**	**2005**
Continuing operations -			
Current provision:			
Federal	$ 7,896	$ 27,640	$ 5,043
State	9,803	1,994	963
Total	17,699	29,634	6,006
Deferred provision (benefit):			
Federal	(4,598)	(3,329)	882
State	557	(385)	407
Total	(4,041)	(3,714)	1,289
Total tax provision on continuing operations	13,658	25,920	7,295
Discontinued operations -			
Current provision:			
Federal			1,570
State			259
Total			1,829
Total tax provision	$ 13,658	$ 25,920	$ 9,124
Effective tax rate	2.00%	4.80%	2.55%

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $6,880. There was no comparable state tax expense for the years ended August 31, 2006 and 2005.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. The difference between the statutory rate and the effective rate (including taxes related to discontinued operations) is summarized as follows:

	Years Ended August 31,		
	2007	**2006**	**2005**
Federal statutory tax rate	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	1.25%	3.10%	3.56%
Earnings not subject to tax at the Partnership level	(34.25)%	(33.30)%	(36.01)%

Effective tax rate	2.00%	4.80%	2.55%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the deferred tax liability were as follows:

	Years Ended August 31,	
	2007	2006
Property, plant and equipment	$ 102,134	$ 105,425
Other, net	(1,063)	2,046
Total deferred tax liability	$ 101,071	$ 107,471

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8. MAJOR CUSTOMERS AND SUPPLIERS:
We had gross sales as a percentage of total revenues to nonaffiliated major customers as follows:

	Years Ended August 31,		
	2007	2006	2005
Midstream and Intrastate transportation and storage segment:			
BP Energy Company	less than 10%	less than 10%	17.8%

Our major customers are in the natural gas operations segments. Our natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while our NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively. Management believes that our portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer of our interstate transportation or propane revenues accounts for 10% or more of our consolidated income.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Years Ended August 31,		
	2007	2006	2005
Midstream and Intrastate transportation and storage segments:			
Unaffiliated			
BP Energy Company	less than 10%	less than 10%	16.0%
Propane segments			
Unaffiliated			
Dynegy	less than 10%	less than 10%	20.6%
Targa Liquids	22.6%	18.2%	less than 10%
Affiliated			
M.P. Oils, Ltd.	20.7%	22.0%	15.4%
Enterprise	22.1%	27.0%	23.7%

On May 7, 2007, Enterprise and its subsidiaries (Enterprise), became related parties upon Enterprise s purchase of approximately 38.9 million ETE Common Units and the acquisition of a 34.9% non-controlling equity interest in ETE s General Partner, LE GP, L.L.C. Prior to the purchase of ETE Common Units, Enterprise had been one of our major propane suppliers providing approximately 27% and 24% of our combined total propane purchases during fiscal years 2006 and 2005, respectively. Between May 7, 2007 and August 31, 2007 we purchased approximately 19.0% of our combined total propane purchases from Enterprise. Titan purchases substantially all of its propane from Enterprise pursuant to an agreement that expires in 2010 (see Note 9).

ETP sold its investment in M-P Energy in October 2007. In connection with the sale, ETP executed a seven-year propane purchase agreement for approximately 90 million gallons per year at market prices plus a nominal fee.

This concentration of suppliers may impact our overall operations either positively or negatively. However, management believes that the diversification of suppliers is sufficient to enable us to purchase all of our supply needs at market prices without a material disruption of operations if supplies are interrupted from any of our existing sources. Although no assurances can be given that supplies of natural gas, propane and NGLs will be readily available in the future, we expect a sufficient supply to continue to be available.

9. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (NGA) proposing a general rate increase to be effective on November 1, 2006. On March 9, 2007, Transwestern

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filed with the FERC its Stipulation and Agreement of Settlement (Stipulation and Agreement) which provides for (i) revised base tariff rates, (ii) the amortization of certain costs, including the Enron Cash Balance Plan, regulatory commission expense, post retirement benefits, the accumulated reserve adjustment regulatory asset, deferred income taxes, and certain non-PCB environmental costs, and (iii) a depreciation rate of 1.20 percent for all transmission plant facilities. On April 27, 2007, FERC approved the Stipulation and Agreement with an effective date of April 1, 2007. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. Transwestern is not required to file a new rate case until October 1, 2011.

The Phoenix project, as filed with FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. Total project costs are estimated to be approximately $710,000 including AFUDC with projected phased-in service dates in the third or fourth calendar quarter of 2008, subject to FERC approval. On September 21, 2007 the FERC issued the final Environmental Impact Statement to Transwestern. Transwestern has incurred expenditures of $96,489 through August 31, 2007 for the Phoenix project.

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of MEP, an approximately 500-mile interstate natural gas pipeline that will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco s interstate natural gas pipeline in Butler, Alabama, is currently pending necessary regulatory approvals. On February 14, 2007, MEP initiated public review of the project pursuant to FERC s NEPA pre-filing review process. MEP filed its application with FERC for a Natural Gas Act Section 7 Certificate of Public Convenience and Necessity in October, 2007. The Section 7 Certificate must be granted before construction may commence. The approximately $1,270,000 pipeline project is expected to be in service by the first calendar quarter of 2009.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a long-term purchase contract for approximately 79 million gallons of propane per year that contains a two-year cancellation provision and a seven year contract to purchase not less than 90 million gallons per year. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment which require fixed monthly rental payments and expire at various dates through 2020. Rental expense under these operating leases totaled approximately $33,247, $18,004 and $8,830 for the years ended August 31, 2007, 2006 and 2005, respectively, and has been included in operating expenses in the accompanying statements of operations. Fiscal year future minimum lease commitments for such leases are:

2008	$ 13,492
2009	11,132
2010	16,117
2011	15,412
2012	14,465
Thereafter	28,170

We have forward commodity contracts which are expected to be settled by physical delivery. Short-term contracts which expire in less than one year require delivery of up to 640,796 MMBtu/d. Long-term contracts require delivery of up to 77,518 MMBtu/d and extend through July 2018.

On October 3, 2006, we entered into a long-term agreement with CenterPoint Energy Resources Corp (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System

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located along the Texas gulf coast region commencing on April 1, 2007. These agreements replace a previous agreement with CenterPoint. Under the terms of the new agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel Storage facility.

In connection with the Partnership s acquisition of the ET Fuel System in June 2004, it entered into an eight year transportation agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 115,600 MMBtu per year (reduced to 100,000 MMBtu per year in January, 2006). We also entered into two eight-year natural gas storage agreements with TXU Shipper to store gas at two natural gas facilities that are part of the ET Fuel System. As of August 31, 2007, 2006 and 2005, respectively, the Partnership was entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month periods ended each May 31st. As a result, the Partnership recognized approximately $10,800, $13,413 and $14,716 in additional fees during the third fiscal quarters of 2007, 2006 and 2005, respectively.

We have signed long-term agreements with several parties committing firm transportation volumes into the East Texas pipeline. Those commitments include an agreement with XTO Energy Inc. (XTO) to deliver approximately 200,000 MMBtu/d of natural gas into the pipeline. The term of the XTO agreement began in June 2004 when the pipeline became operational and expires in June 2012.

During 2005, we entered into two new long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts will require an aggregated capacity of approximately 238,000 MMBtu/d of natural gas and extend through 2011.

Titan has a long-term purchase contract with Enterprise (see Note 12) to purchase substantially all of Titan s propane requirements. The contract continues until March 31, 2010 and contains renewal and extension options. The contract contains various service level agreements between the parties.

We sold our investment in M-P Energy in October 2007. In connection with the sale, we executed a seven-year propane purchase agreement for approximately 90 million gallons per year at market prices plus a nominal fee.

In August 2007 and in connection with a reimbursable agreement entered into by MEP with a financial institution, we executed a percentage guaranty with the same financial institution whereby we would be liable for our 50% of any defaulted payments not made by MEP, plus interest. The reimbursable agreement has a commitment up to $197,000, as amended, and expires in September 2008.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or 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 management believes 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.

FERC/CFTC and Related Matters. On July 26, 2007, the Federal Energy Regulatory Commission (the FERC) issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other dates from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by

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artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha Hub and the Katy Hub near Houston, Texas. Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at negotiated rates, which activity is expected to account for approximately 1.0% of our operating income for our 2007 fiscal year. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based rates would be limited to sales of natural gas to retail customers (such as utilities and other end users) and sales from our own production, and any other sales of natural gas by us would be required to be made at prices that would be subject to the FERC approval. Also on July 26, 2007, the United States Commodity Futures Trading Commission (the CFTC) filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity Exchange Act by attempting to manipulate natural gas prices in the Houston Ship Channel. It is alleged that such manipulation was attempted during the period from late September through early December 2005 to allow us to benefit financially from our commodities derivatives positions.

In its Order and Notice, the FERC is seeking $70,134 in disgorgement of profits, plus interest, and $97,500 in civil penalties relating to these matters. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. In its lawsuit, the CFTC is seeking civil penalties of $130 per violation, or three times the profit gained from each violation, and other ancillary relief. The CFTC has not specified the number of alleged violations or the amount of alleged profit related to the matters specified in its complaint. On October 15, 2007, ETP filed a motion to dismiss in the United State District Court for the Northern District of Texas on the basis that the CFTC has not stated a valid cause of action under the Commodity Exchange Act.

It is our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC and CFTC hold substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

In addition to the FERC and CFTC legal actions, it is also possible that third parties will assert claims against us for damages related to these matters, which parties could include natural gas producers, royalty owners, taxing authorities, and parties to physical natural gas contracts and financial derivatives based on the Platts *Inside FERC* Houston Ship Channel index during the periods in question. In this regard, two natural gas producers have initiated legal proceedings against us, one of which is seeking an unspecified amount of direct, indirect, consequential and punitive damages for alleged manipulation of natural gas prices at the Waha Hub in West Texas and the other is seeking to obtain discovery of information related to our activities prior to further pursuing a claim for manipulation of natural gas prices in the Houston Ship Channel. In addition, a plaintiff has filed a putative class action which purports to be brought on behalf of natural gas traders who purchased and/or sold natural gas futures and options on the New York Stock Mercantile Exchange between December 29, 2003 and December 31, 2005.

We are expensing the legal fees, consultants fees and related expenses relating to these matters in the periods in which such expenses are incurred. In addition, our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the outcome of these matters; however, it is possible that the amount we become obliged to pay as a result of the final resolution of these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of our existing accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our existing accrual for these matters. As our accrual amounts are non-cash, any cash

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payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available for distributions either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariffs, which were filed with and approved by the FERC. As a result, Transwestern believes that is has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. Transwestern does not believe the outcome of this case will have a material adverse effect on its financial position, results of operations or cash flows. A hearing was held on April 24, 2007 regarding Transwestern s Supplemental Brief for Attorneys fees which was filed on January 8, 2007 and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg s opening brief was due July 31, 2007. Appellee s opposition brief is due November 21, 2007.

Transwestern Trespass Actions. Transwestern is managing one threatened trespass action related to right of way (ROW) on Tribal or allottee land. The threatened action concerns 5,100 feet of ROW on private allotments within the Laguna Pueblo that expired on December 28, 2002. Transwestern received a letter dated March 19, 2003 from the United States Department of the Interior, Bureau of Indian Affairs (BIA) on behalf of the two allottees asserting trespass. Transwestern s legal exposure related to this matter is not currently determinable. Negotiations are ongoing on this matter.

Another action involves an agreement with the BIA covering 44 miles of ROW on a total of 68 Navajo allotments. This ROW agreement expired on January 1, 2004. One allottee sent a letter dated January 16, 2004 to the BIA claiming Transwestern trespassed and that allotee s claim of trespass has been settled and his consent to use the property has been acquired. Transwestern filed a renewal application with the BIA during October 2002, and has received two grants from the BIA for allotted lands in New Mexico and Arizona, which are effective through December 31, 2023.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel Storage facility (Cushion Gas). This litigation is referred to 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.

Other Matters. Of the pending or threatened matters in which we or our subsidiaries are a party, none have arisen outside the ordinary course of business except for an action filed by HOLP on November 30, 1999 against SCANA Corporation, Cornerstone Ventures, L.P. and Suburban Propane, L.P. (the SCANA litigation). HOLP received favorable final judgment with respect to the SCANA litigation on all four claims on October 21, 2004, and received $7,700 in net settlement proceeds on June 1, 2006. This amount has been recorded in interest and other income, net in our consolidated statement of operations for the year ended August 31, 2006.

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In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of August 31, 2007 and 2006, an accrual of $30,275 and $32,148, respectively, was recorded as accrued and other current liabilities and other non-current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters.

Environmental

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices, and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for presence of polychlorinated biphenyls (PCBs) which are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue for several years is $12,344. Transwestern received FERC approval for rate recovery of the portion of soil and groundwater remediation not related to PCBs effective April 1, 2007.

Transwestern continues to incur certain costs related to PCBs that could migrate into customers facilities. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing the PCBs. Costs of these remediation activities totaled approximately $354 for the period since acquisition. Future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at August 31, 2007. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for United States Environmental Protection Agency s Spill Prevention, Control and Countermeasures (SPCC) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

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In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the EPA) regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to HOLP, it is believed that HOLP s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

In conjunction with the October 1, 2002 acquisition of the Texas and Oklahoma natural gas gathering and gas processing assets from Aquila Gas Pipeline, Aquila, Inc. (Aquila) agreed to indemnify us for any environmental liabilities that arose from the operation of the assets for the period prior to October 1, 2002. Aquila also agreed to indemnify us for 50% of any environmental liabilities that arose from the operations of Oasis Pipe Line Company prior to October 1, 2002.

We also assumed certain environmental remediation matters related to eleven sites in connection with our acquisition of the HPL System.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our August 31, 2007 or our August 31, 2006 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of August 31, 2007 and 2006, an accrual on an undiscounted basis of $16,455 and $4,387, respectively, was recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors. A receivable of $388 was recorded in our consolidated balance sheets as of August 31, 2007 and 2006, to account for a predecessor s share of certain environmental liabilities of ETC OLP.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for all of the above environmental matters is adequate to cover the potential exposure for clean-up costs.

Our pipeline operations are subject to regulation by the U.S Department of Transportation (DOT) under the Pipeline Hazardous Materials Safety Administration (PHMSA) pursuant to which the PHMSA has established regulations relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas.

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Through August 31, 2007, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2010. Through August 31, 2007, a total of $13,442 of capital costs and $11,785 of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through August 31, 2007, a total of $2,864 of capital costs and $88 of operating and maintenance costs have been incurred for pipeline integrity testing for Transwestern. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

10. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To reduce the impact of this price volatility, we primarily 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. These contracts consist primarily of futures and swaps and are recorded at fair value on the consolidated balance sheets. We have established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. Furthermore, on a bi-weekly basis, management reviews the creditworthiness of the derivative counterparties to manage against the risk of default.

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis swaps to manage our exposure to market fluctuations in the prices of natural gas and NGLs. We enter into these financial instruments with brokers who are clearing members with NYMEX and directly with counterparties in the over-the-counter (OTC) market. We are subject to margin deposit requirements under the OTC agreements and NYMEX positions. NYMEX requires brokers to obtain an initial margin deposit based on an expected volume of the trade when the financial instrument is initiated. This amount is paid to the broker by both counterparties of the financial instrument to protect the broker from default by one of the counterparties when the financial instrument settles. We also have maintenance margin deposits with certain counterparties in the OTC market. The payments on margin deposits occur when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date. We had net deposits with derivative counterparties of $45,490 and $87,806 as of August 31, 2007 and 2006, respectively, reflected as deposits paid to vendors on our consolidated balance sheets.

The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

Non-trading Activities

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in Accumulated Other Comprehensive Income (OCI) until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge s change in fair value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges are included in cost of products sold in the period the hedged transactions occur. Gains and losses deferred in OCI related to cash flow hedges remain in OCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For those financial derivative instruments that do not qualify for hedge accounting, the change in market value is recorded as cost of products sold in the consolidated statements of operations. We reclassified into earnings gains of $162,523, gains of $73,213, and losses of $26,784 for the years ended August 31, 2007, 2006 and 2005, respectively, related to commodity financial instruments that were previously reported in OCI.

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We expect gains of $21,213 to be reclassified into earnings over the next twelve months related to income currently reported in OCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs. The majority of our commodity-related derivatives are expected to settle within the next two years.

In the course of normal operations, we routinely enter into contracts such as forward physical contracts for the purchase and sale of natural gas, propane, and other NGLs, that under SFAS 133, qualify for and are designated as a normal purchase and sales contracts. Such contracts are exempted from the fair value accounting requirements of SFAS 133 and are accounted for using accrual accounting. For contracts that are not designated as normal purchase and sales contracts, the change in market value is recorded in costs of products sold in the consolidated statements of operations. In connection with the HPL acquisition, we acquired certain physical forward contracts that contain embedded options. These contracts have not been designated as normal purchase and sale contracts, and therefore, are marked to market in addition to the financial options that offset them. The Black-Scholes valuation model was used to estimate the value of these embedded options.

Trading Activities

Trading activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain activities where limited market risk is assumed are considered trading for accounting purposes and are executed with the use of a combination of financial instruments including, but not limited to, basis contracts and gas daily contracts. The derivative contracts that are entered into for trading purposes, subject to limits, are recognized on the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in midstream and intrastate transportation and storage revenue in the consolidated statements of operations on a net basis.

The following table details the outstanding commodity-related derivatives as of August 31, 2007 and 2006, respectively:

August 31, 2007	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	14,195,262	2007-2009	$ 5,551
Swing Swaps IFERC	Gas	7,282,500	2007-2008	(514)
Fixed Swaps/Futures	Gas	(590,000)	2007-2009	1,298
Forward Physical Contracts	Gas	(6,437,413)	2007-2008	343
Options	Gas	(976,000)	2007-2008	(346)
Forward/Swaps in Gallons	Propane	8,862,000	2007-2008	777
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(4,922,500)	2007-2008	$ 2,390
Swing Swaps IFERC	Gas	(21,250,000)	2007	(33)
Forward Physical Contracts	Gas		2007	323
Fixed Swaps/Futures	Gas	(10,275,000)	2007	(177)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(10,962,500)	2007-2008	$ 124
Fixed Swaps/Futures	Gas	(11,230,000)	2007-2009	23,078

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August 31, 2006				
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	33,711,140	2006-2009	$ (6,247)
Swing Swaps IFERC	Gas	(37,220,448)	2006-2008	2,618
Fixed Swaps/Futures	Gas	3,607,500	2006-2007	(170)
Forward Physical Contracts	Gas	(7,986,000)	2006-2008	(21,653)
Options	Gas	(1,046,000)	2006-2008	21,653
Forward/Swaps in Gallons	Propane	24,066,000	2006-2007	199
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(2,572,500)	2006-2008	$ 21,995
Swing Swaps IFERC	Gas		2006	(31)
Forward Physical Contracts	Gas	(455,000)	2006	(68)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(34,585,000)	2006-2007	$ (2,987)
Fixed Swaps/Futures	Gas	(37,872,500)	2006-2007	2,043

Estimates related to our gas marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. We also attempt to maintain balanced positions in our non-trading activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist in our trading and non-trading activities, fluctuating commodity prices can impact our financial results and financial position, either favorably or unfavorably.

During the years ended August 31, 2007 and 2006, the Partnership discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified for and designated as cash flow hedges related to forecasted sales of natural gas stored in the Partnership s Bammel storage facilities. The discontinuation resulted from management s determination that the originally forecasted sales of natural gas from the storage facilities were no longer probable of occurring by the end of the originally specified time period, or within an additional two-month period of time thereafter. The determination was made principally due to the unseasonably warm weather that occurred during February and March 2007 and 2006. One of the key criteria to achieve hedge accounting under SFAS 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, the Partnership recognized previously deferred gains of $37,169 and $84,680 from the discontinued application of hedge accounting during the years ended August 31, 2007 and 2006, respectively. There were no such gains recognized during the year ended August 31, 2005. The Partnership classified the unrealized gains as costs of products sold in its consolidated statements of operations.

Interest Rate Risk

We are exposed to market risk for changes in interest rates related to our bank credit facilities. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not cash flow hedges are classified in other income beginning in fiscal 2007. Prior to fiscal 2007, such gains or losses were reported in interest expense.

The following table represents interest rate swap derivatives at August 31, 2007 and 2006:

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August 31, 2007

Term	Notional Amount	Type	SFAS 133 Hedge	Fair Value (Liability)
March 2009	$ 125,000	Pay Fixed 5.14% Receive Float	No	$ (498)

August 31, 2006

Term	Notional Amount	Type	SFAS 133 Hedge	Fair Value Asset (Liability)
April 2007	$ 400,000	LIBOR Forward Starting	Yes	$ (8,699)
October 2006	100,000	Treasury Lock	No	134
October 2006	200,000	LIBOR Forward Starting	No	495
March 2009	125,000	Pay Fixed 5.14% Receive Float	No	519

We reclassified into earnings losses of $893 and gains of $1,384 for the years ended August 31, 2007 and 2006, respectively, related to interest rate swaps that were previously reported in OCI. We expect gains of $429 to be reclassified into earnings over the next twelve months related to income on interest rate financial instruments currently reported in OCI. The amount ultimately realized, however, could differ as interest rates change.

The following table represents pre-tax balances in OCI related to interest rate swaps as of August 31, 2007 and 2006:

August 31, 2007

Date Settled	Term	Notional Amount	Type	SFAS 133 Hedge	Remaining Balance in OCI Income (Loss)
April 2007	2014	400,000	LIBOR Forward Starting	Yes	$ (11,562)
June 2006	2016	200,000	Treasury Lock	Yes	12,597
January 2005	2017	100,000	Treasury Lock	Yes	(280)
					$ 755

August 31, 2006

Date Settled	Term	Notional Amount	Type	SFAS 133 Hedge	Remaining Balance in OCI Income (Loss)
April 2007	2014	$ 400,000	LIBOR Forward Starting	Yes	$ (8,699)
June 2006	2016	200,000	Treasury Lock	Yes	13,593
January 2005	2017	100,000	Treasury Lock	Yes	(313)
					$ 4,581

ETC OLP also had an interest rate swap with a notional amount of $75,000 that matured in October 2005, and had a fair value of $151 as of August 31, 2005. Under the terms of the swap agreement, we paid a fixed rate of 2.76% and received three-month LIBOR with a quarterly settlement. The interest rate swap was not accounted for as a hedge but received mark to market accounting. Accordingly, changes in the fair value were recorded as a component of interest expense in the consolidated statement of operations.

Summary of Derivative Gains and Losses

The following represents gains (losses) on derivative activity for the periods presented:

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	Years Ended August 31, 2007	2006	2005
Commodity-related			
Unrealized gains (losses) recognized in cost of products sold related to commodity-related derivative activity, excluding ineffectiveness	$ 10,709	$ 9,630	$ (16,614)
Ineffective portion of derivatives qualifying for hedge accounting recognized in cost of products sold	183	16,701	(17,821)
Realized gains included in cost of products sold	184,726	138,629	746
Trading unrealized gains (losses) recognized in revenues	(19,393)	(25,255)	47,147
Trading realized gains recognized in revenues	21,555	45,370	3,464
Interest rate swaps			
Unrealized gains (losses) on interest rate swap included in other income (2007) and interest expense (prior to 2007), excluding ineffectiveness	$ (1,646)	$ 276	$ 690
Ineffective portion of derivatives qualifying for hedge accounting included in interest expense	(1,813)	842	(771)
Realized gains on interest rate swap included in interest and other income, net in 2007, and in interest expense in prior periods	33,291	643	1,953

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

11. RETIREMENT BENEFITS:

We sponsor a defined contribution profit sharing and 401(k) savings plan, which covers virtually all employees subject to service period requirements. Profit sharing contributions are made to the plan at the discretion of the Board of Directors and are allocated to eligible employees as of the last day of the plan year. Employer matching contributions are calculated using a discretionary formula based on employee contributions. We made matching contributions of $8,492, $5,722 and $4,106 to the 401(k) savings plan for the years ended August 31, 2007, 2006 and 2005, respectively.

12. RELATED PARTY TRANSACTIONS:

On May 7, 2007, Ray Davis, previously the Co-Chairman of ETE and Co-Chairman and Co-Chief Executive Officer of ETP (retired August 15, 2007), and Natural Gas Partners VI, L.P. (NGP) and affiliates of each, sold approximately 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise GP Holdings, L.P. (Enterprise or EPE). In addition to the purchase of ETE Common Units, Enterprise also acquired a 34.9% non-controlling equity interest in ETE s General Partner, LE GP, L.L.C. (LE GP). As a result of these transactions, EPE and its subsidiaries are considered related parties (see Note 9).

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Between May 7, 2007 (the purchase date of ETE Units) and August 31, 2007, the Operating Partnerships have made the following sales to and purchases from Enterprise and its affiliates:

Enterprise Transactions	Product	Volumes (in thousands)	Dollars
HOLP			
Purchases	Propane - gallons	17,207	$ 20,957
Titan			
Purchases	Propane - gallons	28,283	34,981
ETC OLP			
Sales	NGLs - gallons	464	648
	Natural Gas - MMBtu	1,495	9,768
Purchases	Natural Gas-MMBtu	3,120	22,677
	Natural Gas Imbalances-MMBtu	1,541	7,501

Our propane operations have a combined accounts payable of approximately $8,900 as of August 31, 2007 to Enterprise. Titan has a long-term purchase contract to purchase substantially all of its propane requirements, and as of August 31, 2007 had forward mark to market derivatives for approximately 12.2 million gallons of propane at a fair value of $390 with Enterprise. Additionally, HOLP has a monthly storage contract with TEPPCO Partners, L.P. (an affiliate of Enterprise) for approximately $600 per year.

ETC OLP and Enterprise transport natural gas on each other s pipelines, share operating expenses on jointly-owned pipelines, and ETC OLP sells natural gas to Enterprise. As of August 31, 2007, ETC OLP had an accounts receivable balance of approximately $2,000, an accounts payable balance of approximately $4,600 and an imbalance payable to Enterprise of approximately $7,100.

As of August 31, 2007, ETC OLP had accounts receivable of approximately $700 and accounts payable of approximately $3,800 with an intrastate transportation joint venture. There was no balance as of August 31, 2006. These receivables and payables are for August activity and were paid in September 2007.

As of August 31, 2007 and 2006, we had advances due from a propane joint venture of $15,091 and $3,775, respectively, which are included in advances to and investment in affiliates on our condensed consolidated balance sheets.

Our natural gas midstream and intrastate transportation and storage operations secure compression services from third parties including Energy Transfer Technologies, Ltd., of which Energy Transfer Group, LLC is the General Partner. These entities are collectively referred to as the ETG Entities . Our Chief Executive Officer has an indirect ownership in the ETG Entities. In addition, two of the General Partner s directors serve on the Board of Directors of the ETG Entities. The terms of each arrangement to provide compression services are, in the opinion of independent directors of the General Partner, no less favorable than those available from other providers of compression services. During the years ended August 31, 2007, 2006 and 2005, we made payments totaling $2,382, $2,900 and $900, respectively, to the ETG Entities for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations. As of August 31, 2007 and 2006, accounts payable to ETG related to compressor leases were not significant.

During fiscal year 2006 we entered into a shared services agreement effective upon the initial public offering of ETE. Under the terms of the shared services agreement, ETE pays us an annual administrative fee of approximately $500 for the provision of various general and administrative services. Fees recognized since the inception of this agreement were nominal.

In November 2005 we purchased the remaining 50% equity interest in South Texas Gas Gathering, a joint venture that owns an 80% interest in the Dorado System, a 61-mile gathering system located in South Texas for $675 from an entity that includes one of the General Partner s directors.

In connection with the HPL System acquisition, ETC OLP entered into a short-term loan agreement with ETE, whereby ETC OLP borrowed $174,624 to acquire the working inventory of natural gas stored in the Bammel storage

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facilities with interest based on the Eurodollar Rate plus 3.0% per annum. ETC OLP also incurred $3,109 in debt issuance costs associated with the loan agreement. The loan was paid in full during the year ended August 31, 2005 and $1,554 of 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. In addition, $1,506 of interest expense is included in the consolidated statement of operations for the year ended August 31, 2005 related to the loan with ETE.

13. SUMMARIZED CONDENSED CONSOLIDATING FINANCIAL STATEMENTS:

Prior to July 20, 2007, when the Partnership entered into an Amended and Restated Credit Agreement (see Note 5), our Revolving Credit Facility and Senior Notes were fully and unconditionally guaranteed by ETC OLP and Titan (beginning in fiscal year 2006) and all of their direct and indirect wholly-owned subsidiaries (the Subsidiary Guarantors). In connection with the Partnership entering into the Amended and Restated Credit Agreement (described in more detail in Note 5), all guarantees by ETC OLP and all of its direct and indirect wholly-owned subsidiaries for the Partnership s 5.65% Senior Notes due 2012 and 5.95% Senior Notes due 2015 (the 2005 Senior Notes), and the Partnership s 6.125% Senior Notes due 2017 and 6.625% Senior Notes dues 2036 (the 2006 Senior Notes), were released and discharged. HOLP and its direct and indirect subsidiaries and HHI do not guarantee our Revolving Credit Facility and Senior Notes. Following is our consolidating financial information including our midstream and propane Subsidiary Guarantors, our Non-Guarantor Subsidiaries and the Partnership for fiscal years ended August 31, 2006 and 2005 (the period during which the Partnership debt was guaranteed as noted above). The condensed consolidating financial information presented herein complies with Rule 3-10 of Regulation S-X, is prepared on the equity method, and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET

As of August 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 728	$	$ 2,182	$ 23,131	$	$ 26,041
Marketable securities				2,817		2,817
Accounts receivable, net		570,569	18,154	86,822		675,545
Accounts receivable from related companies	399,140	14,675	21,618	1,007	(435,543)	897
Inventories		289,003	13,507	84,630		387,140
Deposits paid to vendors		87,806				87,806
Exchanges receivable		23,221				23,221
Price risk management assets	629	55,143	367			56,139
Prepaid expenses and other	673	26,751	2,893	11,881		42,198
Total current assets	401,170	1,067,168	58,721	210,288	(435,543)	1,301,804
PROPERTY, PLANT AND EQUIPMENT, net		2,596,015	201,893	515,741		3,313,649
LONG-TERM PRICE RISK MANAGEMENT ASSET		2,040	152			2,192
ADVANCES TO AND INVESTMENT IN AFFILIATES	3,834,189	32,036		136,353	(3,961,234)	41,344
GOODWILL		23,736	278,835	301,838		604,409
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	14,034	4,788	79,460	93,333		191,615
Total assets	$ 4,249,393	$ 3,725,783	$ 619,061	$ 1,257,553	$ (4,396,777)	$ 5,455,013
LIABILITIES AND PARTNERS CAPITAL						
CURRENT LIABILITIES:						
Accounts payable	$ 1,244	$ 522,191	$ 4,955	$ 74,750	$	$ 603,140
Accounts payable to related companies	28,706	404,505		2,863	(435,424)	650
Exchanges payable		24,722				24,722
Customer advances and deposits		16,524	24,623	67,689		108,836
Accrued wages and benefits	2,646	16,164	4,040	17,505	(119)	40,236
Accrued and other current liabilities	13,909	112,533	18,472	15,784		160,698
Price risk management liabilities	8,699	28,219				36,918
Income taxes payable				83		83
Deferred income taxes		629				629
Current maturities of long-term debt			871	39,707		40,578
Total current liabilities	55,204	1,125,487	52,961	218,381	(435,543)	1,016,490
LONG-TERM DEBT, net of discount, less current maturities	2,330,281		679	258,164		2,589,124

LONG-TERM PRICE RISK MANAGEMENT LIABILITIES		1,728				1,728
DEFERRED INCOME TAXES		51,253		55,589		106,842
MINORITY INTERESTS AND OTHER NON-CURRENT LIABILITIES		2,110		1,857		3,967
COMMITMENTS AND CONTINGENCIES						
	2,385,485	1,180,578	53,640	533,991	(435,543)	3,718,151
PARTNERS CAPITAL	1,863,908	2,545,205	565,421	723,562	(3,961,234)	1,736,862
Total liabilities and partners capital	$ 4,249,393	$ 3,725,783	$ 619,061	$ 1,257,553	$ (4,396,777)	$ 5,455,013

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended August 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 6,877,512	$	$	$	$ 6,877,512
Propane			47,063	752,295		799,358
Other			5,908	176,318		182,226
Total revenue		6,877,512	52,971	928,613		7,859,096
COSTS AND EXPENSES:						
Cost of products sold - midstream and transportation and storage		5,963,422				5,963,422
Cost of products sold - propane			30,751	462,891		493,642
Cost of products sold - other			1,252	110,000		111,252
Operating expenses		203,221	21,433	198,335		422,989
Depreciation and amortization		58,222	3,812	55,381		117,415
Selling, general and administrative	17,256	70,442	2,950	16,857		107,505
Total costs and expenses	17,256	6,295,307	60,198	843,464		7,216,225
OPERATING INCOME (LOSS)	(17,256)	582,205	(7,227)	85,149		642,871
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(96,342)	47	(301)	(29,166)	11,905	(113,857)
Equity in earnings (losses) of affiliates	618,225	(514)		35	(618,225)	(479)
Gain on disposal of assets		679		172		851
Interest and other income (expense), net	11,226	7,631	(7)	7,675	(11,905)	14,620
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	515,853	590,048	(7,535)	63,865	(618,225)	544,006
Income tax expense (benefit)	(1)	(18,345)	9	(7,583)		(25,920)
INCOME BEFORE MINORITY INTERESTS	515,852	571,703	(7,526)	56,282	(618,225)	518,086
Minority interests		(1,349)		(885)		(2,234)
NET INCOME	$ 515,852	$ 570,354	$ (7,526)	$ 55,397	$ (618,225)	$ 515,852

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended August 31, 2005

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:					
Midstream and transportation and storage	$	$ 5,383,625	$	$	$ 5,383,625
Propane			641,071		641,071
Other	116		143,986		144,102
Total revenue	116	5,383,625	785,057		6,168,798
COSTS AND EXPENSES:					
Cost of products sold - midstream and transportation and storage		4,911,366			4,911,366
Cost of products sold - propane			384,186		384,186
Cost of products sold - other			85,963		85,963
Operating expenses		136,001	183,553		319,554
Depreciation and amortization		40,322	52,621		92,943
Selling, general and administrative	13,361	36,706	12,668		62,735
Total costs and expenses	13,361	5,124,395	718,991		5,856,747
OPERATING INCOME (LOSS)	(13,245)	259,230	66,066		312,051
OTHER INCOME (EXPENSE):					
Interest expense	(44,475)	(18,582)	(31,427)	1,467	(93,017)
Loss on extinguishment of debt		(9,550)			(9,550)
Equity in earnings (losses) of affiliates	407,679	(415)	39	(407,679)	(376)
Gain (loss) on disposal of assets		756	(1,086)		(330)
Interest and other income (expense), net	(501)	3,041	(442)	(1,467)	631
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	349,458	234,480	33,150	(407,679)	209,409
Income tax expense (benefit)	(108)	(935)	(6,252)		(7,295)
INCOME BEFORE MINORITY INTERESTS	349,350	233,545	26,898	(407,679)	202,114
Minority interests		(189)	(542)		(731)
INCOME FROM CONTINUING OPERATIONS	349,350	233,356	26,356	(407,679)	201,383
DISCONTINUED OPERATIONS:					
Income (loss) from discontinued operations		149,796	(1,829)		147,967
NET INCOME	$ 349,350	$ 383,152	$ 24,527	$ (407,679)	$ 349,350

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended August 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (92,454)	$ 523,548	$ 3,380	$ 109,410	$	$ 543,884
CASH FLOWS FROM INVESTING ACTIVITIES:						
Cash paid for acquisitions, net of cash acquired	(572,947)	(17,124)	(1,153)	(19,419)	24,458	(586,185)
Working capital settlement on prior year acquisitions		19,653				19,653
Capital expenditures		(632,835)	(3,053)	(44,276)		(680,164)
Advances to and investment in affiliates	(157,387)			(4,651)	157,387	(4,651)
Proceeds from the sale of assets		3,025	812	3,104		6,941
Net cash used in investing activities	(730,334)	(627,281)	(3,394)	(65,242)	181,845	(1,244,406)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from borrowings	2,530,737	19,716	486	278,809		2,829,748
Principal payments on debt	(1,550,456)		(305)	(366,690)		(1,917,451)
Proceeds from borrowings from affiliates	1,598,527	1,859,631	4,850		(3,463,008)	
Payments on borrowings from affiliates	(1,864,481)	(1,571,234)	(27,293)		3,463,008	
Net proceeds from issuance of Common Units	132,383					132,383
Capital contribution from General Partner	2,784	57,387		100,000	(157,387)	2,784
Distributions to parent		(261,805)		(64,657)	326,462	
Distribution from subsidiaries	316,027			10,435	(326,462)	
Distributions to partners	(343,771)					(343,771)
Debt issuance costs	(2,044)					(2,044)
Net cash provided by (used in) financing activities	819,706	103,695	(22,262)	(42,103)	(157,387)	701,649
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(3,082)	(38)	(22,276)	2,065	24,458	1,127
CASH AND CASH EQUIVALENTS, beginning of period	3,810	38	24,458	21,066	(24,458)	24,914
CASH AND CASH EQUIVALENTS, end of period	$ 728	$	$ 2,182	$ 23,131	$	$ 26,041

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended August 31, 2005

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (41,651)	$ 134,239	$ 76,830	$	$ 169,418
CASH FLOWS FROM INVESTING ACTIVITIES:					
Cash paid for acquisitions, net of cash acquired		(1,106,382)	(25,462)		(1,131,844)
Capital expenditures	(9)	(155,830)	(40,620)		(196,459)
Proceeds from the sale of discontinued operations		191,606			191,606
Cash invested in subsidiaries	(1,628,195)	(51)	(2,304)	1,628,195	(2,355)
Proceeds from the sale of assets		997	4,306		5,303
Net cash used in investing activities	(1,628,204)	(1,069,660)	(64,080)	1,628,195	(1,133,749)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	2,631,000	80,000	243,034		2,954,034
Principal payments on debt	(1,280,000)	(805,000)	(252,931)		(2,337,931)
Proceeds from borrowings from affiliates		174,624			174,624
Payments on borrowings from affiliates		(174,624)			(174,624)
Advances (to) from affiliates	(192,494)	192,494			
Net proceeds from issuance of Limited Partner Units	507,724				507,724
Capital contributions from General Partner	10,418	1,613,195	15,000	(1,628,195)	10,418
Distributions to parent		(194,175)	(32,577)	226,752	
Distributions from subsidiaries	211,147		15,605	(226,752)	
Distributions to partners	(207,039)				(207,039)
Debt issuance costs	(16,597)	(3,109)			(19,706)
Net cash provided by (used in) financing activities	1,664,159	883,405	(11,869)	(1,628,195)	907,500
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,696)	(52,016)	881		(56,831)
CASH AND CASH EQUIVALENTS, beginning of period	9,506	52,054	20,185		81,745
CASH AND CASH EQUIVALENTS, end of period	$ 3,810	$ 38	$ 21,066	$	$ 24,914

14. REPORTABLE SEGMENTS:

Our financial statements reflect four reportable segments which conduct their business exclusively in the United States of America, as follows:

ETC OLP:

- midstream operations
- intrastate transportation and storage operations

ET Interstate:

- interstate transportation operations

HOLP and Titan:

- retail propane operations

As of December 1, 2006, with the completion of our acquisition of Transwestern, we have a new reporting segment for our interstate transportation operations. As a result, the comparability of the segment operations information is affected by this addition. The volumes and results of operations data for fiscal year 2007 do not include the interstate operations for periods prior to Transwestern s acquisition on December 1, 2006. The comparability of the segment data for fiscal year 2007 to the prior years is also affected by the allocation of administrative expenses, as discussed further below. The comparability of the segment operations is also affected by our purchase of Titan in June 2006 and the HPL System in January 2005. The fiscal year 2006 volumes and results of operations for our propane segment do not include Titan for periods before its acquisition on June 1, 2006. The fiscal year 2005 volumes and results of operations for our intrastate transportation and storage segment do not include the HPL System for periods prior to its acquisition on January 1, 2005.

Segments below the quantitative thresholds are classified as other . The components of the other classification have not met any of the quantitative thresholds for determining reportable segments. As a result of the HPL System acquisition during fiscal year 2005, management redefined the transportation operations to transportation and storage operations. Management has included the wholesale propane operations in other for all periods presented in this report because such operations are not material.

Midstream and intrastate transportation and storage segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

See Note 1, Business Operations for a detailed description of the operations of each of our reportable segments.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general, administrative expenses, gain (loss) on disposal of assets, minority interests, interest expense, earnings (losses) from equity investments and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. Effective with the Transwestern acquisition on December 1, 2006, we began allocating administration expenses from the Partnership to our Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC). The amounts allocated to the midstream and intrastate transportation segments, propane segment and interstate transportation segment for the year ended August 31, 2007 were $11,357, $10,067 and $4,388, respectively. These amounts were offset by costs allocated to the Partnership from the Operating Partnerships for support services. The amounts allocated to the Partnership, using the MMFC, from the midstream and intrastate transportation and propane segments for the year ended August 31, 2007 were $5,221 and $2,187, respectively. No such amounts were allocated to the Partnership from the interstate transportation segment for the year ended August 31, 2007.

As of August 31, 2007 advances to and investment in affiliates includes our investment in North Side Loop (NSL), a 50% joint venture included in our intrastate transportation and storage segment, and our investment in MEP, which is included in our intrastate transportation segment. Equity in earnings for the fiscal year ended August 31, 2007 includes primarily earnings from CCEH.

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The following table presents the financial information by segment for the following periods:

	Years Ended August 31,		
	2007	2006	2005
Volumes:			
Midstream			
Natural gas MMBtu/d - sold	941,140	1,552,753	1,578,833
NGLs bbls/d - sold	25,657	10,425	12,707
Transportation and storage			
Natural gas MMBtu/d - transported	6,124,423	4,633,069	3,495,434
Natural gas MMBtu/d - sold	1,400,753	1,580,638	1,361,729
Interstate transportation			
Natural gas MMBtu/d - transported	1,802,109		
Natural gas MMBtu/d - sold	19,680		
Retail propane gallons (in thousands)	604,269	429,118	406,334

	Years Ended August 31,		
	2007	2006	2005
Revenues:			
Midstream	$ 2,853,496	$ 4,223,544	$ 3,246,772
Eliminations	(1,562,199)	(2,359,256)	(471,255)
Intrastate transportation and storage	3,915,932	5,013,224	2,608,108
Interstate transportation (see Note 2)	178,663		
Retail propane and other retail propane related	1,284,867	879,556	709,473
All other	121,278	102,028	75,700
Total revenues	$ 6,792,037	$ 7,859,096	$ 6,168,798
Cost of Sales:			
Midstream	$ 2,632,187	$ 4,000,461	$ 3,102,539
Eliminations	(1,562,199)	(2,359,256)	(471,255)
Intrastate transportation and storage	3,137,712	4,322,217	2,280,082
Interstate transportation			
Retail propane and other retail propane related	759,634	515,418	403,740
All other	110,872	89,476	66,409
Total cost of sales	$ 5,078,206	$ 6,568,316	$ 5,381,515
Depreciation and Amortization:			
Midstream	$ 23,388	$ 15,744	$ 12,580
Intrastate transportation and storage	56,145	42,477	27,742
Interstate transportation	27,972		
Retail propane and other retail propane related	70,833	58,036	51,487
All other	824	1,158	1,134
Total depreciation and amortization	$ 179,162	$ 117,415	$ 92,943

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	Years Ended August 31, 2007	2006	2005
Operating Income (Loss):			
Midstream	$ 123,176	$ 151,507	$ 99,133
Intrastate transportation and storage	488,098	430,698	160,098
Interstate transportation	95,650		
Retail propane and other retail propane related	124,263	76,055	66,902
All other	1,735	1,899	(683)
Selling general and administrative expenses not allocated to segments	(3,270)	(17,288)	(13,399)
Total operating income	$ 829,652	$ 642,871	$ 312,051
Other items not allocated by segment:			
Interest expense	$ (175,563)	$ (113,857)	$ (93,017)
Loss on extinguishment of debt			(9,550)
Equity in earnings (losses) of affiliates	5,161	(479)	(376)
Gain (loss) on disposal of assets	(6,310)	851	(330)
Interest and other income, net	37,999	14,620	631
Income tax expense	(13,658)	(25,920)	(7,295)
Minority interests	(1,142)	(2,234)	(731)
	(153,513)	(127,019)	(110,668)
Income from continuing operations	$ 676,139	$ 515,852	$ 201,383

	August 31, 2007	2006
Total Assets:		
Midstream	$ 801,968	$ 682,652
Intrastate transportation and storage	3,534,013	3,029,124
Interstate transportation	1,653,363	
Retail propane and other retail propane related	1,593,863	1,619,732
All other	125,221	123,505
Total	$ 7,708,428	$ 5,455,013

	August 31, 2007	2006
Additions to Property, Plant and Equipment including acquisitions (accrual basis):		
Midstream	$ 201,646	$ 15,907
Intrastate transportation and storage	827,859	701,988
Interstate transportation	1,345,637	
Retail propane and other retail propane related	65,125	263,008
All other	2,015	6,194
Total	$ 2,442,282	$ 987,097

15. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners under EITF 03-6 and variations in the weighted average units outstanding used in computing such amounts. Earnings per unit are computed on a stand-alone basis for each quarter and total year under EITF 03-6. HOLP s and Titan s businesses are seasonal due to weather conditions in their service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income 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. Sales to commercial and industrial customers are much less weather sensitive. ETC OLP s business is also seasonal due to the operations of ET Fuel

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System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot 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.

	Quarter Ended				
Fiscal 2007:	**November 30**	**February 28**	**May 31**	**August 31**	**Total Year**
Revenues	$ 1,388,445	$ 2,062,480	$ 1,714,786	$ 1,626,326	$ 6,792,037
Gross Profit	301,102	576,664	427,399	408,666	1,713,831
Operating income	107,842	358,362	191,308	172,140	829,652
Net income	71,032	311,114	157,466	136,527	676,139
Limited Partners interest in net income	17,731	250,547	97,504	74,481	440,263
Basic net income per limited partner unit	$ 0.15	$ 1.33	$ 0.71	$ 0.54	$ 3.32
Diluted net income per limited partner unit	$ 0.15	$ 1.33	$ 0.71	$ 0.54	$ 3.31

	Quarter Ended				
Fiscal 2006:	**November 30**	**February 28**	**May 31**	**August 31**	**Total Year**
Revenues	$ 2,416,620	$ 2,449,816	$ 1,420,335	$ 1,572,325	$ 7,859,096
Gross Profit	325,993	440,985	272,968	250,834	1,290,780
Operating income	171,610	280,820	118,118	72,323	642,871
Net income	119,808	250,785	111,912	33,347	515,852
Limited Partners interest in net income	99,325	223,090	81,803	(7,351)	396,867
Basic net income per limited partner unit	$ 0.76	$ 1.37	$ 0.70	$ (0.07)	$ 3.16
Diluted net income per limited partner unit	$ 0.76	$ 1.36	$ 0.70	$ (0.07)	$ 3.15

The results of operations for the fourth quarter of fiscal year 2006 were significantly affected by litigation and contingency provisions and the loss from the Titan operations subsequent to its acquisition date. The Limited Partner interest in net income and income per Limited Partner Unit were significantly impacted as a result of the application of EITF 03-6 due to the distributions for such quarter (declared subsequent to August 31, 2006) exceeding the net income for the quarter. That resulted in an allocation of income from the Limited Partners to the General Partner for the Incentive Distribution Rights in excess of the net income allocable to the Limited Partner for the quarter.

16. SUBSEQUENT EVENTS:

On October 5, 2007, we entered into an agreement to acquire the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the Canyon acquisition). The Canyon Gathering System has over 400,000 of dedicated acres under long-term contracts. The Canyon assets include a gathering system in the Piceance-Uinta Basin which consists of over 1,800 miles of 2-inch to 16-inch pipe with a projected capacity of over 300,000 MMbtu/d, as well as six processing plants for NGL extraction and gas treatment with a processing capacity of 90 MMcf/d. Some of the largest U.S. producers are active in the area and are major customers of the system. The cash paid for this acquisition was financed as discussed below.

On October 5, 2007, we entered into a credit agreement providing for a $310,000, 364-day term loan credit facility (the Term Loan Agreement). Borrowings under the Term Loan Agreement were used to fund the purchase price for the Canyon acquisition and for general corporate purposes. The facility is a single draw term loan with an applicable Eurodollar rate plus 0.600% per annum based on our current rating by the rating agencies or at Base Rate for designated period. The indebtedness under the Term Loan Agreement is unsecured and is not guaranteed by any of our subsidiaries. Borrowings under the Term Loan Agreement, upon proper notice to the administrative agent, may be prepaid in whole or in part without premium or penalty. The Term Loan Agreement requires any proceeds received from debt or equity issuance, assets sales, or accordion increases be used to make a mandatory prepayment on the outstanding loan balance. The Term Loan Agreement contains covenants that are similar to the covenants of the ETP Credit Facility (see Note 5).

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On October 10, 2007, we filed a Form 8-K indicating that we plan to change our year end to December 31. Our next full fiscal year will begin on January 1, 2008.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a 15(e) and 15d 15(e) of the Exchange Act). Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of August 31, 2007 to provide reasonable assurance that information required to be disclosed by us in the reports that we file to submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms.

Our management including the Chief Executive Officer and Chief Financial Officer of our General Partner does not expect that our disclosure controls and procedures or our internal controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. The inherent limitations in all control systems include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Based upon the evaluation, our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded as of August 31, 2007 that our disclosure controls and procedures are adequate and effective to ensure that information required to be disclosed by us in our periodic filings under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

Management s Report on Internal Controls over Financial Reporting

The management of Energy Transfer Partners, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer of our General Partner, and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO framework). In conducting our evaluation of the effectiveness of our internal control over financial reporting, we excluded the acquisition of Transwestern in December 2006 due to its size and complexity. Collectively, this acquisition constituted approximately 21% of our total consolidated assets as of August 31, 2007, and approximately 3% of our total consolidated revenues and approximately 12% of our consolidated net income for the year then ended. Such exclusion was in accordance with Securities and Exchange Commission guidance that an assessment of a recently acquired business may be omitted in management s report on internal controls over financial reporting, provided the acquisition took place within twelve months of management s evaluation.

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We continue to evaluate the business of Transwestern and are making various changes to its operating and organizational structure based on our business plan. We are in the process of implementing our internal control structure over the operations of Transwestern. We expect that this effort will continue into future fiscal quarters of 2008 due to the magnitude of the business.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of August 31, 2007.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited Energy Transfer Partners, L.P. s (a Delaware limited partnership) internal control over financial reporting as of August 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Energy Transfer Partners, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Energy Transfer Partners, L.P. s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

As indicated in Management s Report on Internal Control over Financial Reporting, management s assessment of and conclusion on the effectiveness of internal control over financial reporting did not include an assessment of the effectiveness of internal controls over financial reporting of Transwestern Pipeline Company, LLC (Transwestern). Transwestern was acquired on December 1, 2006 and has been included in the consolidated financial statements of the Partnership since that date. Transwestern constituted approximately 21% of total assets as of August 31, 2007 and 3% of revenues and 12% of net income for the year then ended. Our audit of internal control over financial reporting of Energy Transfer Partners, L.P. also did not include an evaluation of the internal controls over financial reporting of Transwestern.

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

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

In our opinion, Energy Transfer Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of August 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

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We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Energy Transfer Partners, L.P. and subsidiaries, as of August 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the three years in the period ended August 31, 2007 and our report dated October 29, 2007 expressed an unqualified opinion on those consolidated financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas

October 29, 2007

Changes in Internal Controls over Financial Reporting

Other than the changes resulting from the Transwestern acquisition (discussed below), there have been no changes in our internal controls over financial reporting (as defined in Rules 13a 15(f) or Rule 15d 15(f)) that occurred in the three months ended August 31, 2007 that have materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Transwestern Acquisition

On December 1, 2006, we completed the Transwestern acquisition. In recording the Transwestern acquisition, we followed our normal accounting procedures and internal controls. Our management also reviewed the operations of Transwestern from the date of the acquisition that are included in our earnings for the fiscal year ended August 31, 2007. In addition, we obtained disclosure information from former Transwestern employees and reviewed the Transwestern historical audited and subsequent unaudited interim financial statements and notes accompanying the financial statements. We are continuing to integrate our internal controls into these operations, and it is expected that this effort will continue into future fiscal quarters of 2008. As a result, Transwestern s business has been excluded from our fiscal 2007 internal control assessment.

We have excluded Transwestern s business from our internal control assessment for the following reasons:

Given the time required to test the operating effectiveness of Transwestern s controls and the due date for our attestation required by Section 404 of the Sarbanes Oxley Act of 2002, it was not practical from a timing or resource standpoint for us to conduct a thorough assessment prior to our 2007 fiscal year end.

Transwestern utilized a financial accounting computer system and other industry-specific computer applications that are different from those we used through August 31, 2007. For various business reasons, Transwestern s business remained on these systems. As a result, we believe that reporting on the controls of the current computer system used by Transwestern will not be useful to our investors since the use of certain of these systems may be discontinued after August 31, 2007.

We continue to evaluate Transwestern s business and are making various changes to its operating and organizational structure based on our business plan. We are in the process of implementing our internal control structure over the operations of Transwestern. We expect that this effort will continue into future fiscal quarters of 2008 due to the magnitude of the business. The assessment and documentation of internal controls requires a complete implementation of controls operating in a stable and effective environment.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Partnership Management

ETP GP (the General Partner) is our General Partner. The General Partner manages and directs all of our activities. The activities of the General Partner are managed and directed by its General Partner, ETP LLC. Our officers and directors are officers and directors of ETP LLC. The owners of the General Partner and ETP LLC may appoint up to eleven persons at least three of whom qualify as independent directors to serve on ETP LLC s Board of Directors. In addition, persons serving as ETP LLC s Chairman, President or Chief Executive Officer also serve on ETP LLC s Board of Directors. Each of these persons is individually a manager of ETP LLC, and are collectively referred to as our Board of Directors.

At all times during our 2007 fiscal year, our Board of Directors was comprised of its Chairman, ETP LLC s President, four persons who qualify as independent under the NYSE s standards for audit committee members, and five other persons.

Corporate Governance

The Board of Directors of our General Partner has adopted both a Code of Business Conduct applicable to our Directors, Officers and Employees, and Corporate Governance Guidelines for Directors and the Board. Current copies of our Code of Business Conduct, Corporate Governance Guidelines and charters applicable to the committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Common Unitholder requesting such information.

Annual Certification

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this report. In fiscal year 2007, our Chief Executive Officer provided to the New York Stock Exchange the annual CEO certification regarding our compliance with the New York Stock Exchange s corporate governance listing standards.

Independent Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Independent Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Partnership and its Common Unitholders. Any matters approved by the Independent Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Common Unitholders.

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE s standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 401 of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee member Paul E. Glaske qualified as an Audit Committee financial expert during the Partnership s 2007 fiscal year. A description of the qualifications of Mr. Glaske may be found elsewhere in this Item 10 under Directors and Executive Officers of the General Partner.

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting

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controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by SAS 61, *Communications with Audit Committees,* and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Board of Directors adopts the Charter for the Audit Committee. Bill W. Byrne has served as a member of the Audit Committee of the Board of Directors since his appointment in February 2002. In February 2004, Paul E. Glaske was appointed as a member of the Audit Committee. In December 2005, John D. Harkey, Jr. was appointed as a member of the Audit Committee. During our fiscal year 2006, Mr. Glaske served as the Chairman of the Audit Committee. At the October 2006 meeting of the Board of Directors, Messrs. Byrne, Glaske and Harkey were re-elected to serve on the Audit Committee. Mr. Harkey currently serves as a member or chairman of the audit committee of four other publicly traded companies, in addition to his service as a member of the Audit Committee of our General Partner and the Audit Committee of the General Partner of Energy Transfer Equity, L.P. As required by Rule 303A.07 of the NYSE Listed Company Manual, the Board of Directors of our General Partner has determined that such simultaneous service does not impair Mr. Harkey s ability to effectively serve on our Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of ETP LLC has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans adopted by our Common Unitholders, including the performance standards or other restrictions pertaining to the vesting of any such awards. A director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, the Partnership or its subsidiaries. Bill W. Byrne and K. Rick Turner were appointed to serve as the members of the Compensation Committee in February 2004. In December 2005, Michael K. Grimm was appointed as a member of the Compensation Committee. During our fiscal year 2006, Mr. Turner served as the Chairman of the Compensation Committee. At the October 2006 meeting of the Board of Directors, Messrs. Byrne, Turner and Grimm were re-elected to serve on the Compensation Committee.

Matters relating to the nomination of Directors or Corporate Governance matters are addressed to and determined by the full Board of Directors.

Code of Business Conduct

The Board of Directors has adopted a Code of Business Conduct applicable to our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. The Code of Business Conduct is available on our website at www.energytransfer.com and in print to any Unitholder that requests it. Amendments to, or waivers from, the Code of Business Conduct will also be available on our website and reported as may be required under SEC rules, however, any technical, administrative or other non-substantive amendments to the Code of Business Conduct may not be posted. Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Meetings of Non-management Directors and Communications with Directors

Our non-management Directors meet in regularly scheduled sessions. The Chairman of each of the Partnership s Audit, Independent and Compensation Committees alternate as the presiding director of such meetings.

The Partnership has established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any of the Partnership s independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of the Partnership s General Counsel at Energy Transfer Partners, L.P., 3738 Oak Lawn Avenue, Dallas, Texas 75219 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

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Directors and Executive Officers of the General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of October 16, 2007. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	51	Chief Executive Officer and Chairman of the Board of Directors
Mackie McCrea	48	President Midstream
R.C. Mills	70	President Propane
Brian J. Jennings	47	Chief Financial Officer
Jerry J. Langdon	56	Chief Administrative and Compliance Officer
Thomas P. Mason	51	General Counsel and Secretary
Karen Z. Hicks	45	Vice President of Administration and Controller
Ray C. Davis	65	Director
Bill W. Byrne	77	Director
David R. Albin	48	Director
Kenneth A. Hersh	44	Director
Paul E. Glaske	74	Director
K. Rick Turner	49	Director
Ted Collins, Jr.	69	Director
John W. McReynolds	56	Director
Michael Grimm	52	Director
John D. Harkey, Jr.	47	Director

Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:

Kelcy L. Warren. Mr. Warren became the sole Chief Executive Officer and Chairman of the Board of our General Partner effective as of August 15, 2007. Mr. Warren had previously served as the Co-Chief Executive Officer and Co-Chairman of the Board of our General Partner in that capacity since the combination of the midstream and transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Warren served as President of the general partner of ET Company I, Ltd., having served in that capacity since 1996. From 1996 to 2000, he served as a director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 20 years of business experience in the energy industry.

Mackie McCrea. Mr. McCrea is the President Midstream of our General Partner and has served in that capacity since March 2007. Previously he served as the Senior Vice President Commercial Development since the combination of the operations of ETC OLP and HOLP in January 2004. In March 2005, Mr. McCrea was named president of ETC

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OLP. Prior to the combination of the operations of ETC OLP and HOLP, Mr. McCrea served as Senior Vice President Business Development and Producer Services of the General Partner of ETC OLP and ET Company I, Ltd., having served in that capacity since 1997.

R.C. Mills. Mr. Mills is the President Propane of our General Partner since March 2007. Previously he was the Executive Vice President and Chief Operating Officer of our General Partner and had served in these capacities since January 2004. In March 2005, Mr. Mills was named President of HOLP. Mr. Mills has over 40 years of experience in the propane industry. Mr. Mills joined Heritage in 1991 as Executive Vice President and Chief Operating Officer. Before coming to Heritage, Mr. Mills spent 25 years with Texgas Corporation in various capacities, including as the Executive Vice President and Chief Operations Officer.

Brian J. Jennings. Mr. Jennings has served as Chief Financial Officer of our General Partner since March 2007. Prior to joining ETP, Mr. Jennings served as Senior Vice President of Corporate Finance & Development and Chief Financial Officer for Devon Energy Corporation from March 2000 to December 2006. Prior to joining Devon in March 2000, Mr. Jennings was a Managing Director in the Energy Investment Banking Group of PaineWebber Inc. Mr. Jennings began his energy career in 1984, joining ARCO International Oil & Gas, a subsidiary of the Atlantic Richfield Company.

Jerry J. Langdon. Mr. Langdon has served as the Chief Administration and Compliance Officer of our General Partner since June 2007. Prior to June 2007, Mr. Langdon has been the Executive Vice President for Public and Regulatory Affairs and the Chief Compliance Officer for Reliant Energy, Inc. since 2003. Prior to joining Reliant, Mr. Langdon served as the President of EPGT Texas Pipeline, L.P., a subsidiary of El Paso Corporation that owned and operated 8,000 miles of natural gas, NGL and LPG pipelines. Mr. Langdon also served for five years as a Commissioner of the Federal Energy Regulatory Commission (FERC), the federal agency that regulated certain sales and transportation activities of natural gas pipelines engaging in interstate commerce.

Thomas P. Mason. Mr. Mason has served as General Counsel and Secretary for Energy Transfer since February 2007. Prior to joining ETP, he was a partner in the Houston office of Vinson & Elkins, where he had been working with Energy Transfer for the past several years. Mr. Mason has specialized in securities offerings and mergers and acquisitions for 25 years. Mr. Mason joined Vinson & Elkins as a partner in 2001 after a 19-year career at Andrews & Kurth, a Houston-based law firm.

Karen Z. Hicks. Ms. Hicks is Vice President of Administration and Controller of our General Partner, serving in that capacity since September 2004 and has served as Controller of our General Partner since July 2002. Ms. Hicks has spent 18 years in the propane industry, all of which have been with Energy Transfer and Heritage. Ms. Hicks started her career with Heritage as Accounting Manager and was promoted to Manager of Financial Reporting when the Partnership went public in 1996. In December 2000, Ms. Hicks was promoted to Assistant Controller and was promoted to Partnership Controller July 2002. Prior to her career in the propane industry, Ms. Hicks was a bank examiner for the State of Montana for three years.

Ray C. Davis. Mr. Davis was the Co-Chief Executive Officer and Co-Chairman of the Board of Directors of our General Partner since the combination of the midstream and transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004 until his retirement from these positions effective August 15, 2007. Mr. Davis also served as Co-Chief Executive Officer of the General Partner of ETC OLP and Co-Chairman of the Board of Directors of the General Partner of ETE, positions he held since their formation in 2002. Mr. Davis now serves as a director of the General Partners of ETP and ETE. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Davis served as Vice President of the General Partner of ET Company I, Ltd., the entity that operated ETC OLP s midstream assets before it acquired Aquila, Inc. s midstream assets, having served in that capacity since 1996. From 1996 to 2000, he served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as Chairman of the Board of Directors and Chief Executive Officer of Cornerstone Natural Gas, Inc. Mr. Davis has more than 32 years of business experience in the energy industry. Mr. Davis became a venture partner of Natural Gas Partners, L.L.C. in September 2007.

Bill W. Byrne. Mr. Byrne is the principal of Byrne & Associates, LLC, an investment company based in Tulsa, Oklahoma. Prior to his retirement in 1992, Mr. Byrne was Vice President of Warren Petroleum Company, the gas liquids division of Chevron Corporation, serving in that capacity from 1982 to 1992. Mr. Byrne has served as a director of our General Partner since 1992 and is a member of both the Audit Committee and the Compensation Committee. Mr. Byrne is a former president and director of the National Propane Gas Association (NPGA).

David R. Albin. Mr. Albin is a managing partner of the Natural Gas Partners private equity funds, and has served in that capacity or similar capacities since 1988. Prior to his participation as a founding member of Natural Gas Partners, L.P. in 1988, he was a partner in the $600 million Bass Investment Limited Partnership. Prior to joining Bass Investment Limited Partnership, he was a member of the oil and gas group in the investment banking division of Goldman, Sachs & Co. He currently serves as a director of NGP Capital Resources Company. Mr. Albin has served as a director of our General Partner since February 2004 and has served as a director of LE GP, L.L.C. since October 2002.

Kenneth A. Hersh. Mr. Hersh is the Chief Executive Officer of NGP Energy Capital Management and is a managing partner of the Natural Gas Partners private equity funds and has served in those or similar capacities since 1989. Prior to joining Natural Gas Partners, L.P. in 1989, he was a member of the energy group in the investment banking division of Morgan Stanley & Co. He currently serves as a director of NGP Capital Resources Company and as a director of the general partner of Eagle Rock Energy Partners, L.P. Mr. Hersh has served as a director of our General Partner since February 2004 and has served as a director of LE GP, L.L.C. since October 2002.

Paul E. Glaske. Mr. Glaske retired as Chairman and Chief Executive Officer of Blue Bird Corporation, the largest manufacturer of school buses with manufacturing plants in three countries. Prior to becoming president of Blue Bird in 1986, Mr. Glaske served as the president of the Marathon LeTourneau Company, a manufacturer of large off-road mining and material handling equipment and off-shore drilling rigs. He currently is a member of the board of directors of BorgWarner, Inc.; of Chicago, Illinois where he serves as chair of the governance committee. In addition, Mr. Glaske serves on the board of directors of both Lincoln Educational Services in New Jersey, and Camcraft, Inc., in Illinois. Mr. Glaske has served as a director of our General Partner since February 2004 and is chairman of the Audit Committee and a member of the Independent Committee.

K. Rick Turner. Mr. Turner has been employed by Stephens family entities since 1983. He is currently Senior Managing Principal of The Stephens Group, LLC. He first became a private equity principal in 1990 after serving as the Assistant to the Chairman, Jackson T. Stephens. His areas of focus have been oil and gas exploration, natural gas gathering, processing industries, and power technology. Mr. Turner currently serves as a director of Atlantic Oil Corporation; SmartSignal Corporation; JV Industrials, LLC, JEBCO Seismic, LLC; North American Energy Partners Inc., Seminole Energy Services, LLC, BTEC Turbines LP, and the General Partner of Energy Transfer Partners, LP (ETP) and the General Partner of Energy Transfer Equity, LP (ETE). Prior to joining Stephens, he was employed by Peat, Marwick, Mitchell and Company. Mr. Turner earned his B.S.B.A. from the University of Arkansas and is a non-practicing Certified Public Accountant.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. Mr. Collins previously served as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988, Mr. Collins was President of Enron Oil and Gas Company, and its predecessors, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quaser Petroleum Company. Mr. Collins is a director and serves on the Finance Committee of Hanover Compression Company, and is a director and the Chairman of the Governance Committee of Encore Acquisition Company. Mr. Collins has served as a director of our General Partner since August 2004.

John W. McReynolds. Mr. McReynolds is a director, and the President and Chief Financial Officer of Energy Transfer Equity, L.P. (ETE). Mr. McReynolds has served as the President of ETE since March 2005, and as a director and the Chief Financial Officer of ETE since August 2005. Prior to becoming President of ETE, Mr. McReynolds was a partner with the international law firm of Hunton & Williams LLP for over 20 years. As a lawyer, he specialized in energy-related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in numerous arbitration, litigation and government proceedings, including as an expert in special projects for boards of directors of public companies. Mr. McReynolds has served a director of our General Partner since August 2004.

Michael K. Grimm. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and has served as its President and Chief Executive Officer since 1995. Prior to the formation of Rising Star, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for thirteen years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Houston Producers Forum, and Fort Worth Wildcatters. Mr. Grimm has served as a director of our General Partner since December 2005.

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John D. Harkey, Jr. Mr. Harkey has served as Chief Executive Officer and Chairman of Consolidated Restaurant Companies, Inc., and as Chief Executive Officer and Vice Chairman of Consolidated Restaurant Operations Inc. since 1998. Mr. Harkey currently serves on the Board of Directors and Audit Committee of Leap Wireless International, Inc., Emisphere Technologies, Inc., and Loral Space & Communications, Inc. He also serves on the Executive Board of Circle Ten Council of the Boy Scouts of America. Mr. Harkey has served as a director of our General Partner since December 2005. In May 2006 Mr. Harkey was elected as a director and member of the Audit Committee of ETE.

Compensation of the General Partner

ETP GP does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Partnerships. ETP GP and its affiliates performing services for the Partnership and the Operating Partnerships are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to, but not paid directly by, the Partnership, if any, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Following the Energy Transfer Transactions in January 2004, the employees of the General Partner became employees of our Operating Partnerships, and thus, the ETP GP has not incurred additional reimbursable costs since that time.

Compliance with Section 16(a) of the Securities and Exchange Act

Section 16(a) of the Securities and Exchange Act of 1934 requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership and changes in beneficial ownership with the Securities and Exchange Commission (SEC). Officers, directors and greater than 10% Unitholders are required by SEC regulations to furnish the General Partner with copies of all Section 16(a) forms.

Based solely on our review of the copies of such forms received by us, or written representations from certain reporting persons that no Forms 5 were required for those persons, we believe that during fiscal year ending August 31, 2007, all filing requirements applicable to its officers, directors, and greater than 10% beneficial owners were met in a timely manner other than a late filing of a Form 3 for Mr. Jennings and late filings of a Form 4 for Mr. Grimm and a Form 4 for Mr. Collins.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our general partner, Energy Transfer Partners GP, L.P. (ETP GP), which in turn is managed by its general partner, Energy Transfer Partners, L.L.C., which we refer to herein as our General Partner . Energy Transfer Equity, L.P. (ETE), a publicly-traded limited partnership, owns 100% of our General Partner and approximately 46% of our outstanding units. All of our employees are employed by and receive employee benefits from our subsidiary operating partnerships.

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of our management functions. As a result, the executive officers of our General Partner are essentially our executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The executive officers we refer to in this discussion as our named executive officers are the following officers of our General Partner:

Kelcy L. Warren, Chief Executive Officer;

Mackie McCrea, President - Midstream;

R. C. Mills, President - Propane;

Brian J. Jennings, Chief Financial Officer;

Jerry J. Langdon, Chief Administrative and Compliance Officer; and

Thomas P. Mason, General Counsel and Secretary.

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In addition to the named executive officers identified above, the following individuals were executive officers of our General Partner during the year ended August 31, 2007 but were no longer executive officers as of August 31, 2007:

- Ray C. Davis, former Co-Chief Executive Officer; and
- H. Michael Krimbill, former President and Chief Financial Officer.

Our General Partner s Philosophy for Compensation of Executives

In general, our General Partner s philosophy for executive compensation is based on the premise that a significant portion of the executive s compensation should be incentive-based and that the base salary levels should be competitive in the marketplace for executive talent and abilities. Our General Partner also believes the incentives should be competitive in the market place and balanced between short and long-term performance. Our General Partner believes this balance is achieved by the payment of annual cash bonuses based on the achievement of financial performance objectives for a fiscal year set at the beginning of such fiscal year, and the annual grant of restricted unit awards under our 2004 Unit Plan which is intended to provide a longer term incentive to our key employees to focus their efforts to increase the market price of our publicly traded units and to increase the cash distribution we pay to our Unitholders. Under the 2004 Unit Plan, we have generally issued restricted unit awards that vest over a three-year period based on the achievement of annual performance objectives relating to the total return of our units (defined as the appreciation in market price for our units plus total amount of cash distributions for our fiscal year) as compared to the total return of a peer group of other publicly traded limited partnerships determined by the compensation committee of our General Partner (Compensation Committee). Our General Partner believes that these incentive arrangements are important in attracting and retaining our executives and key employees as well as motivating these individuals to achieve our business objectives. The incentive-based compensation also reflects the importance of aligning the interests of the executive officers with those of our Unitholders.

While we are responsible for the direct payment of the compensation of our named executive officers as employees of ETP, ETP does not participate or have any input in any decisions as to the compensation policies of our General Partner or the compensation levels of the executive officers of our General Partner. As discussed below, ETP does not have a compensation committee. The compensation committee of the board of directors of our General Partner (the Compensation Committee) is responsible for the approval of the compensation policies and the compensation levels of these executive officers. We directly incur the payment to these executive officers in lieu of receiving an allocation of overhead related to executive compensation from our General Partner. For the year ended August 31, 2007, we paid 100% of the compensation of the executive officers of our General Partner as we represent the only business managed by our General Partner.

Our General Partner is ultimately controlled by the general partner of Energy Transfer Equity, L.P., which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our partnership agreement with respect to its ownership of a 2% general partner interest and the incentive distribution rights specified in our partnership agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our partnership agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner s executive officers. Our General Partner s distribution rights are described in detail in Note 6 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

Compensation Committee

We are a limited partnership and our units are listed on the New York Stock Exchange, or NYSE. Although the rules of the NYSE do not require publicly traded limited partnerships to have a compensation committee, the board of directors of our General Partner has established a Compensation Committee that is composed of three directors of our General Partner who our General Partner has determined to be independent (as that term is defined in the applicable NYSE rules and Rule 10A-3 of the Exchange Act). The members of the Compensation Committee are Mr. K. Rick Turner, Mr. Michael K. Grimm and Mr. Bill W. Byrne.

The Compensation Committee s responsibilities include, among other duties, the following:

annually review and approve goals and objectives relevant to compensation of the Chief Executive Officer, or the CEO;

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annually evaluate the CEO s performance in light of these goals and objectives, and make recommendations to the board of directors of our General Partner with respect to the CEO s compensation levels based on this evaluation;

based on input from, and discussion with, the CEO, make recommendations to the board of directors of our General Partner with respect to non-CEO executive officer compensation, including incentive compensation and compensation under equity based plans;

make determinations with respect to the grant of equity-based awards to executive officers under the 2004 Unit Plan;

periodically evaluate the terms and administration of ETP s short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with ETP s goals and objectives;

periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;

periodically evaluate the compensation of the directors;

retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and

perform other duties as deemed appropriate by the board of directors of our General Partner.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

attract, retain and reward talented executive officers and key management employees, by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;

motivate executive officers and key employees to achieve strong financial and operational performance;

emphasize performance-based compensation; and

reward individual performance.

Methodology

The Compensation Committee considers relevant data available to it to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The Compensation Committee also considers individual performance, levels of responsibility, skills and experience.

Components of Executive Compensation

For the year ended August 31, 2007, the compensation paid to our named executive officers consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- vesting of previously issued equity-based unit awards issued pursuant to our 2004 Unit Plan;
- compensation resulting from the vesting of equity issuances made by an affiliate; and
- 401(k) contributions.

Base Salary. As discussed above, the base salaries of our named executive officers for the fiscal year ended August 31, 2007 were determined by the board of directors of our General Partner based on recommendations from the Compensation Committee which took into account the recommendations of Mr. Warren and Mr. Davis, the then-current Co-Chief Executive Officers of our General Partner. For the fiscal year ending August 31, 2008, the Compensation Committee has engaged a consultant to assist in the determination of compensation levels.

Annual Bonus. In addition to base salary, we award our named executive officers discretionary annual cash bonuses that are paid in a lump sum following the end of the fiscal year. The annual bonuses are awarded based upon our

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achievement of financial performance objectives during the year for which the bonuses are awarded and in part upon the contribution of each individual to our profitability and success during the year for which the bonuses are awarded. The Compensation Committee considers the recommendation of management in determining the financial performance objectives for a particular fiscal year and the aggregate amount of cash bonuses to be paid to the executives and key employees based on satisfying these performance objectives at specified levels. The CEO makes the determinations, based on recommendations from other executives and key employees in charge of specific business units, as to the specific bonus amounts for each participant in this bonus plan. The Compensation Committee alone determines the annual cash bonus amounts for our Chief Executive Officer and our other named executive officers except for those executives who participate in the annual bonus plan (specifically, Mackie McCrea and R.C. Mills).

Equity Awards. Our 2004 Unit Plan authorizes the Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other rights related to our units at such times and upon such terms and conditions as it may determine in accordance with the 2004 Unit Plan. The Compensation Committee determined and/or approved the number of unit grants awarded to our named executive officers and also the vesting structure of those unit awards under our 2004 Unit Plan. A description of the unit awards and related vesting structure is contained in the Unit Awards Table below. To date, the only awards under the 2004 Unit Plan have consisted of restricted unit awards. All of the awards of restricted units granted to the named executive officers under our 2004 Unit Plan have required the achievement of performance objectives such that up to one-third of the total number of units subject to an award will vest each year based on the level of achievement of the performance objectives for such year, with 100% of such one-third vesting if the total return for our units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the Compensation Committee, 65% of such one-third vesting if the total return of our units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of our units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of our units for the year plus the aggregate per unit cash distributions received for the year. For fiscal 2007, the peer group used to make the total return comparison consisted of Suburban Propane Partners L.P., Plains All-American Pipeline L.P., NuStar Energy L.P., Sunoco Logistics Partners L.P., Magellen Midstream Partners L.P., AmeriGas Partners L.P., ONEOK Partners L.P., Buckeye Partners L.P., Kinder Morgan Energy Partners L.P., Enterprise Product Partners L.P., Teppco Partners L.P., Enbridge Energy Partners L.P. and Ferrellgas Partners L.P. No distributions are made on the unit awards prior to vesting. The vesting of these awards is also subject to continued employment with us or our General Partner as of the end of each applicable year. Each of Messrs, Warren, McCrea, Mills, Davis and Krimbill have received unit awards under the 2004 Unit Plan, a portion of which vested during our 2007 fiscal year.

On October 2, 2007 the Compensation Committee of our General Partner determined that based on our performance for the year ended August 31, 2007, of the employee awards scheduled to vest on September 1, 2007, 25% of the awards vested and 75% of the awards were forfeited. The Compensation Committee of our General Partner also approved a special one-time grant of the number of awards that were forfeited. Such awards are not subject to performance objectives but are subject only to continued employment with us through the first anniversary of the grant date of October 2, 2007. These Compensation Committee actions affected all employee awards, including awards granted to executive officers.

The issuance of Common Units pursuant to the 2004 Unit Plan is intended to serve as a means of incentive compensation, therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

Compensation expense is measured as the grant date market value of our units, reduced by the present value of the distributions that will not be received during the vesting period. We assumed a weighted average risk-free interest rate of 4.45%, for the year ended August 31, 2007 in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each employee grant. For the employee awards outstanding during the year ended August 31, 2007, the grant-date average per unit cash distributions were estimated to be $5.50. Upon vesting, ETP Common Units are issued.

The unit awards under our 2004 Unit Plan generally require the continued employment of the recipient during the vesting period. The Compensation Committee has in the past and may in the future, but is not required to, accelerate the vesting of unvested unit awards in the event of the termination or retirement of an executive officer. During the year ended August 31, 2007, the Compensation Committee did not accelerate the vesting of any unvested unit awards under the 2004 Unit Plan granted to Mr. Davis at the time of his retirement as Co-Chief Executive Officer of our General Partner.

Affiliate Equity Awards. During our year ended August 31, 2007, certain of our named executive officers received an award from a partnership, the general partner of which is owned and controlled by the President of the general partner of ETE, which awards granted these named executive officers certain rights related to units of ETE previously issued by ETE to the President of the general partner of ETE. These rights include the economic benefits of ownership of these units based on a 5-year vesting schedule whereby the recipient will vest in the units at a rate of 20% per year. These awards were, and any future awards will be, made at the discretion of the President of the general partner of ETE and we have no input in any such decision. Neither we nor ETE pay any of the costs related to such awards. Based on generally accepted accounting principles covering related party transactions and unit-based compensation arrangements, we are recognizing non-cash compensation expense over the vesting period based on the grant date per unit market value of the ETE units awarded the ETP employees assuming no forfeitures. Awards granted for the year ended August 31, 2007 result in a total non-cash compensation expense of approximately $23.5 million to be recognized over the related vesting

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period. As these units were outstanding prior to these awards, the awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE. The recipients of the awards and the amount of non-cash compensation expense recognized during fiscal year 2007 and to be recognized in future periods related to these awards are as follows:

Year Ended August 31,	Brian J. Jennings	Jerry J. Langdon	Thomas P. Mason	Total
2007	$ 2,387,910	$ 324,614	$ 2,478,593	$ 5,191,117
2008	3,730,020	1,805,517	2,969,016	8,504,553
2009	2,161,321	1,023,600	1,716,843	4,901,764
2010	1,289,820	620,795	1,008,471	2,919,086
2011	679,770	348,310	507,754	1,535,834
2012	209,160	142,167	119,323	470,650

Qualified Retirement Plan Benefits. We have established a defined contribution 401(k) plan which covers substantially all of our employees including our named executive officers. The plan is subject to the provisions of the Employee Retirement Income Security Act of 1974 (ERISA). Employees who have completed one hour of service and have attained age 21 years of age are eligible to participate. Employees may elect to defer up to 100% of defined eligible compensation after applicable taxes, as limited under the Code. We may contribute to the plan on behalf of our employees under a discretionary matching or a discretionary profit sharing arrangement, both of which are based on a percentage of compensation. Employee salary deferrals are always 100% vested. Employer contributions vest upon completion of one year of service. For the year ended August 31, 2007, the Compensation Committee approved an employer matching contribution of up to six percent.

Health and Welfare Benefits. All full-time employees, including our executive officers, may participate in our health and welfare benefit programs including medical coverage and disability insurance.

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner. Our 2004 Unit Plan provides for immediate vesting of all unvested unit awards in the event of a change in control. A change of control as defined under our 2004 Unit Plan means any of (i) the date on which Energy Transfer Partners GP, L.P. ceases to be the general partner of the Partnership; (ii) the date that ETE ceases to own, directly or indirectly through wholly-owned subsidiaries, in the aggregate at least 51% of the capital stock or equity interests of Energy Transfer Partners GP, L.P.; (iii) the sale of all or substantially all of ETP s assets (other than to any Affiliate of ETE); or (iv) a liquidation or dissolution of ETP. No such accelerated vesting occurred during fiscal year 2007.

Deferred Compensation Arrangements. We do not have any deferred compensation arrangements or defined benefit pension plans or other post retirement benefits for our named executive officers. Our named executive officers also do not receive any payments that would represent a perquisite.

Director Compensation

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. On October 17, 2006, the Compensation Committee recommended, following its receipt and review of an independent third-party compensation study, and the Board of Directors approved, an amendment to the 2004 Unit Plan to provide that annual grants of ETP Common Units to non-employee directors of our General Partner will be equal to $25,000 divided by the fair market value of Common Units on that date. All other annual director s grants will be measured at September 1 of each year.

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

We account for our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), in accordance with the requirements of SFAS No. 123R over the vesting period of the awards, as discussed further in Note 6 to our consolidated financial statements.

Report of Compensation Committee

The compensation committee of the board of directors of our General Partner has reviewed and discussed the section entitled Compensation Discussion and Analysis with the management of Energy Transfer Partners, L.P. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form-10K.

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The Compensation Committee of the Board of Directors of Energy Transfer Partners, L.L.C., the general partner of the Energy Transfer Partners GP, L.P., the general partner of Energy Transfer Partners, L.P.

K. Rick Turner
Michael K. Grimm
Bill W. Byrne

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933 as amended, or the Securities Exchange Act of 1934 as amended except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

FISCAL YEAR 2007 SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Equity Awards ($) (2)	Option Awards ($)	Non-equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Kelcy L. Warren (4) Chief Executive Officer	2007	$ 500,000	$ 750,000	$ 209,998	$	$	$	$ 14,000	$ 1,473,998
Mackie McCrea President Midstream	2007	380,769	500,000	150,303				14,481	1,045,553
R. C. Mills President Propane	2007	388,482	300,000	93,251				8,162	789,895
Brian J. Jennings (5) Chief Financial Officer	2007	189,231						2,387,910	2,577,141
Jerry J. Langdon (6) Chief Administrative and Compliance Officer	2007	53,846						324,614	378,460
Thomas P. Mason (7) General Counsel and Secretary	2007	238,462						2,478,593	2,717,055
Ray C. Davis (8) Former Co-Chief Executive Officer	2007	498,654	750,000	(126,762)				9,768	1,131,660
H. Michael Krimbill (9) Former President and Chief Financial Officer	2007	337,581	700,000	(117,895)				8,705	928,391

(1) The bonus amounts for the executive officers of ETP represents the discretionary bonus paid in December 2006 for fiscal year 2006. The annual bonus for such executive officers is approved by the Compensation Committee and paid in December of each year. The actual bonus to be paid for fiscal year 2007 has not yet been determined. We have recorded accruals for the total bonus estimated for all officers and employees at August 31, 2007, but at this time have not allocated the total bonus pool to individuals.

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(2) The amounts in this column reflect the amount of compensation expense recognized in our consolidated financial statements for the year ended August 31, 2007, determined in accordance with SFAS 123(R). The compensation expense for fiscal year 2007 is net of the impact of the cumulative adjustment of prior period compensation expense resulting from the unit forfeiture in 2007 due to the failure to achieve specified performance conditions.
The negative compensation expense reflected above for Messrs. Davis and Krimbill is due to the reversal of previously recorded compensation expense resulting from the forfeiture of units upon their retirement or resignation. The value of the units forfeited by Mr. Davis upon his retirement was $1,338,120. The value of the units forfeited by Mr. Krimbill upon his resignation was $1,291,966.

(3) The amounts in this column include (a) the amount of compensation expense recognized in our consolidated financial statements for the year ended August 31, 2007 related to equity-based awards of units in ETE owned by an affiliate to certain of our named executive officers, as discussed further above and in Note 6 to our consolidated financial statements, and (b) contributions to the 401(k) plan made by ETP on behalf of the named executive officers.

(4) Mr. Warren has voluntarily determined that (a) his salary subsequent to October 19, 2007 will be reduced to $1.00 per year (plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits) (b) he will not accept a cash bonus related to our 2007 fiscal year and (c) he will no longer accept any equity awards under the Unit Plan.

(5) Mr. Jennings began employment on March 6, 2007.

(6) Mr. Langdon began employment on July 1, 2007.

(7) Mr. Mason began employment on February 1, 2007.

(8) Mr. Davis retired on August 15, 2007.

(9) Mr. Krimbill resigned on January 15, 2007.

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FISCAL YEAR 2007 ALL OTHER COMPENSATION TABLE

Name	Year	Perquisites and Other Personal Benefits ($)	Tax Reimbursements ($)	Life Insurance Premiums ($) (1)	Company Contributions to Retirement and 401(k) Plans ($) (2)	Severance Payments / Accruals ($)	Change in Control Payments / Accruals ($) (3)	Affiliate Equity Awards (4)	Total ($)
Kelcy L. Warren Chief Executive Officer	2007	$	$	$	$ 14,000	$	$	$	$ 14,000
Mackie McCrea President Midstream	2007				14,481				14,481
R. C. Mills President Propane	2007				8,162				8,162
Brian J. Jennings Chief Financial Officer	2007							2,387,910	2,387,910
Jerry J. Langdon Chief Administrative and Compliance Officer	2007							324,614	324,614
Thomas P. Mason General Counsel and Secretary	2007							2,478,593	2,478,593
Ray C. Davis Former Co-Chief Executive Officer	2007				9,768				9,768
H. Michael Krimbill Former President and Chief Financial Officer	2007				8,705				8,705

(1) The executive officers life insurance premiums are paid by the Partnership on the same basis as all other employees. Since this represents non-discriminatory group life insurance available to all salaried employees, the premiums paid are not included in the table above.

(2) Messrs. Jennings, Langdon and Mason receive a 401(k) match. However, as of August 31, 2007, none of those executive officers has vested in such contribution match. Vesting in the 401(k) matching contribution occurs upon the completion of one year of service.

(3) Does not include the value of unvested unit awards under the 2004 Unit Plan that would fully vest upon a change of control as defined in the 2004 Unit Plan, which value was $1,222,940 for Mr. Warren, $975,802 for Mr. McCrea, and $672,201 for Mr. Mills based on the closing unit price per ETP Common Unit on August 31, 2007. Unvested units with an August 31, 2007 valuation of $546,420 for Mr. Warren, $455,298 for Mr. McCrea and $325,250 for Mr. Mills were forfeited on September 1, 2007 due to the failure to achieve performance conditions.
Also does not include the August 31, 2007 value of unvested affiliate equity awards granted to Messrs. Jennings, Langdon and Mason, that would fully vest upon a change of control as defined in the affiliate equity awards, which value was $11,025,000 for Mr. Jennings, $3,675,000 for Mr. Langdon, and $10,106,250 for Mr. Mason, based on the August 31, 2007 closing unit price per ETE Common Unit.

(4) Consists of the amount accrued for the fiscal year ended August 31, 2007 even though no portion of the affiliate equity awards had vested as of August 31, 2007.

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FISCAL YEAR 2007 GRANTS OF PLAN-BASED AWARDS TABLE

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**All Other Unit Awards: Number of Units (#)**	**All Other Option Awards: Number of Securities Underlying Options (#)**	**Exercise or Base Price of Option Awards ($ / Sh)**	**Grant Date Fair Value of Unit Awards (3)**
Kelcy L. Warren Chief Executive Officer	11/01/06	$	$	$		15,000	15,000			$	$ 406,490
Mackie McCrea President Midstream	11/01/06					11,000	11,000				298,106
R. C. Mills President Propane	11/01/06					7,000	7,000				189,682
Brian J. Jennings Chief Financial Officer											
Jerry J. Langdon Chief Administrative and Compliance Officer											
Thomas P. Mason General Counsel and Secretary											
Ray C. Davis Former Co-Chief Executive Officer (2)	11/01/06										
H. Michael Krimbill(1) Former President and Chief Financial Officer	11/01/06										

(1) Mr. Krimbill forfeited 25,335 awards upon his resignation on January 15, 2007 of which 14,000 were granted during fiscal year 2007.
(2) Mr. Davis forfeited 27,000 awards upon his retirement on August 15, 2007 of which 15,000 were granted during fiscal year 2007.
(3) We have computed the grant date fair value of unit awards in accordance with SFAS 123(R), as further described above and in Note 6 to our consolidated financial statements.

The amounts above do not include the equity awards granted to certain of ETP s named executive officers in equity of ETE held by a partnership controlled by Mr. McReynolds. These awards are not plan-based awards, and the final decision on such awards is in the sole discretion of Mr. McReynolds. The amount of compensation expense recognized during fiscal year 2007 and to be recognized in future periods for such awards is detailed above by individual recipient.

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FISCAL YEAR 2007 OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END TABLE

		Option Awards					Stock Awards			
		Number of Securities Underlying Unexercised Options (#)	Number of Securities Underlying Unexercised Options (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options						Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested
Name	Award Year	Exercisable	Unexercisable	(#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#) (1)	Market Value of Units That Have Not Vested ($) (1)	Equity Incentive Plan Awards: Number of Units That Have Not Vested (#) (2)	($) (3)
Kelcy L. Warren	2007				$			$	15,000	$ 780,600
Chief Executive Officer	2006								6,000	312,240
	2005								6,000	312,240
Mackie McCrea	2007								11,000	572,440
President Midstream	2006								5,334	277,581
	2005								5,333	277,529
R. C. Mills	2007								7,000	364,280
President Propane	2006								4,000	208,160
	2005								4,000	208,160
Brian J. Jennings	2007									
Chief Financial Officer	2006									
	2005									
Jerry J. Langdon	2007									
Chief Administrative and Compliance Officer	2006									
	2005									
Thomas P. Mason	2007									
General Counsel and Secretary	2006									
	2005									
Ray C. Davis	2007									
Former Co-Chief Executive Officer	2006									
	2005									
H. Michael Krimbill	2007									
Former President and Chief Financial Officer	2006									
	2005									

(1) The amounts above do not include the equity awards granted to certain of ETP s named executive officers in equity of ETE held by a partnership controlled by Mr. McReynolds. These awards are not plan-based awards, and the final decision on such awards is in the sole discretion of Mr. McReynolds.

(2) For each named executive in the table, the un-vested 2005 awards are scheduled to vest September 1, 2007. The un-vested 2006 awards are scheduled to vest 1/2 on September 1, 2007 and 1/2 on September 1, 2008. The un-vested 2007 awards are scheduled to vest 1/3 on September 1, 2007; 1/3 on September 1, 2008; and 1/3 on September 1, 2009. The Compensation Committee of our General Partner determined that performance criteria were not fully achieved as of August 31, 2007 and as a result, 75% of the awards eligible to vest September 1, 2007 were forfeited.

(3) This market value was computed as the number of unvested awards at August 31, 2007 multiplied by our Common Unit closing per unit market price at August 31, 2007.

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FISCAL YEAR 2007 OPTION EXERCISES AND UNITS VESTED TABLE

	Option Awards		Unit Awards	
Name	**Number of Units Acquired on Exercise (#)**	**Value Realized on Exercise ($)**	**Number of Units Acquired on Vesting (#)**	**Value Realized on Vesting ($) (1)**
Kelcy L. Warren Chief Executive Officer		$	9,000	$ 523,702
Mackie McCrea President Midstream			7,999	465,457
R. C. Mills President Propane			6,000	321,043
Brian J. Jennings Chief Financial Officer				
Jerry J. Langdon Chief Administrative and Compliance Officer				
Thomas P. Mason General Counsel and Secretary				
Ray C. Davis Former Co-Chief Executive Officer			9,000	523,702
H. Michael Krimbill Former President and Chief Financial Officer			8,499	454,758

(1) This value represents the amount reported on the officer s W-2, which value represents approximately 92% of the market value of the units on the date of vesting. The value is discounted due to the restrictions placed on the sale of the units for two years.

Director Compensation, including Unit Grants

As indicated below, we do not have our own board of directors. We are managed by our General Partner. The directors identified below represent the non-employee, independent directors of our General Partner. For convenience purposes, we directly pay the compensation to the directors rather than paying an allocation from our General Partner since we represent only business managed by our General Partner. Mr. Davis is presently a non-employee director (resignation effective August 15, 2007) but he received no fees as a director during fiscal year 2007.

The compensation paid to the non-employee, independent directors of our General Partner is reflected in the following table. The table excludes any board member who is either an employee of our General Partner or is not considered to be independent, specifically Messrs. Warren, Davis, Krimbill, Albin, and Hersh.

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FISCAL YEAR 2007 NON-EMPLOYEE, INDEPENDENT DIRECTOR COMPENSATION TABLE

Name	Fees Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)	Total ($)
Bill W. Byrne	$ 68,000	$ 19,003	$	$ 87,003
Paul E. Glaske	66,150	22,207		88,357
K. Rick Turner	51,050	28,532		79,582
Ted Collins, Jr.	40,000	25,874		65,874
John W. McReynolds (1)		8,177		8,177
Michael Grimm	44,800	33,352		78,152
John D. Harkey, Jr.	55,300	33,352		88,652

(1) This relates to unit grants to Mr. McReynolds prior to his employment with ETE.

In fiscal year 2007, non-employee directors of our General Partner received an annual fee of $40,000 plus $1,200 for each committee meeting attended. Additionally, the Chairman of the Audit Committee receives an annual fee of $15,000 and the members of the audit committee receive an annual fee of $10,000. The Chairman of the Compensation Committee receives an annual fee of $7,500 and the members of the compensation committee receive an annual fee of $5,000. Employee directors, including Messrs. Warren, Davis (prior to August 15, 2007) and Krimbill (prior to January 15, 2007), do not receive any fees for service as directors. The total amount of director fees we paid during fiscal year 2007 to the directors of our General Partner was $325,300.

In addition, the non-employee directors participate in our 2004 Unit Plan. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, ETP, or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of up to 2,000 ETP Common Units (the Initial Director s Grant). Commencing on September 1, 2004 and each September 1 thereafter that this Plan is in effect, each Director Participant who is in office on such September 1, shall automatically receive an award of Units equal to $25,000 ($15,000 prior to October 17, 2006) divided by the fair market value of a Common Units on such date (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of one third per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a change in control, as defined by the Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which have not yet vested on the date a Director Participant ceases to be a director shall vest on such terms as may be determined by the Compensation Committee. No distributions are paid until the unit awards vest.

Compensation expense is measured on the grant date market value of our units, reduced by the present value of the distributions that will not be received during the vesting period. We assumed a weighted average risk-free interest rate of 3.80% for the year ended August 31, 2007, in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each Director Grant. For the Director Awards granted during the year ended August 31, 2007, the grant-date average per unit cash distributions were estimated to be $4.95.

On September 1, 2007, Annual Director Grants of 2,880 units were awarded and 5,220 Director Grants vested and Common Units were issued**.**

On October 17, 2006, the Compensation Committee recommended, following its receipt and review of an independent third-party compensation study, and the Board of Directors approved, an amendment to the 2004 Unit Plan to provide that Annual Director s Grants shall be equal to $25,000 divided by the fair market value of Common Units on that date. All other Annual Director s Grants shall be measured at September 1 of each year. On October 17, 2006, 3,240 Annual Director Grants were awarded.

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The number of unit awards granted to non-employee, independent directors during fiscal year 2007, units vested and issued during fiscal year 2007, and unvested unit awards held by non-employee directors as of August 31, 2007 is as follows:

FISCAL YEAR 2007 UNVESTED UNIT AWARDS

Name	Unit Awards in Fiscal Year 2007	Units Vested and Issued in Fiscal Year 2007	Number of Unvested Units at August 31, 2007
Bill W. Byrne	540	1,366	1,046
Paul E. Glaske	540	1,699	1,046
K. Rick Turner	540	1,699	2,380
Ted Collins, Jr.	540	1,699	2,380
John W. McReynolds (1)		1,563	1,566
Michael Grimm	540	666	1,874
John D. Harkey, Jr.	540	666	1,874

(1) This relates to unit grants to Mr. McReynolds prior to his employment with ETE.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

At the time of our initial public offering, the equity owners 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.

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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	(2)	3,592	(1)	$ 194,615	
2004 Unit Plan	(2)	557,437	(1)	30,201,937	997,807
Equity compensation plans not approved by security holders					
Total		561,029		$ 30,396,552	997,807

(1) Valued as of October 16, 2007. Actual exercise price may differ depending on the Common Unit price on the date such units vest.
(2) As of August 31, 2007.

The following table sets forth certain information as of October 16, 2007, regarding the beneficial ownership of our securities by certain beneficial owners, all directors and named executive officers of the General Partner of our General Partner, each of the named executive officers and all directors and named executive officers of the General Partner of our General Partner as a group, of our Common Units and Class E Units. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Energy Transfer Partners, L.P. Units

Title of Class	Name and Address of Beneficial Owner (1)	Beneficially Owned	Percent of Class
Common Units	Kelcy L. Warren (3)	18,500	*
	R.C. Mills (4)	703,101	*
	Mackie McCrea (3)	24,249	*
	Brian J. Jennings		*
	Jerry J. Langdon		*
	Thomas P. Mason		*
	Ray C. Davis (3)	53,000	*
	Bill W. Byrne	160,458	*
	David R. Albin (5)		*
	Kenneth A. Hersh (5)		*
	Paul E. Glaske	56,477	*
	Michael K. Grimm	6,022	*
	John D. Harkey, Jr.	846	*
	K. Rick Turner (5)	10,144	*
	Ted Collins, Jr.	56,184	*
	John W. McReynolds	16,411	*
	All Directors and Named Executive Officers as a Group (16 persons)	1,105,392	*
	ETE (6)	62,500,797	45.599%
	FHM Investments, L.L.C. (3)	1,308	*

Class E Units	Heritage Holdings, Inc. (7)	8,853,832	100%

* Less than one percent (1%)

(1) The address for Mr. Warren is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Heritage Holdings is 8801 S. Yale Avenue, Suite 310, Tulsa, Oklahoma 74137. The address for Messrs. Albin and Hersh is 125 E. John Carpenter Freeway, Suite 600, Irving, Texas 75062. The address for Mr. McCrea is 800 E. Sonterra Blvd.,

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San Antonio, Texas 78258. The address for Mr. Mills is 5000 Sawgrass Village, Suite 4, Ponte Vedra Beach, Florida 32082. The address for ETE and Mr. McReynolds is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Ms. Hicks is 754 River Rock Drive, Helena, Montana, 59602. The address for FHS Investments is 2215 B Renaissance Dr., Suite 5, Las Vegas, Nevada 89119. The address for FHM Investments is 7005 Quail Rock Lane, Reno, Nevada 89511. The address for Mr. Davis is 2838 Woodside Street, Dallas, Texas 75204. The address for Messrs. Byrne, Grimm, Collins, Glaske, Harkey, and Turner is 3738 Oak Lawn Avenue, Dallas, Texas 75219.

(2) Beneficial ownership for the purposes of the foregoing table is defined by Rule 13d-3 under the Securities Exchange Act of 1934. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof (Voting Power) or to dispose or direct the disposition thereof (Investment Power) or has the right to acquire either of those powers within sixty (60) days.

(3) Due to the ownership by Messrs. Warren, McCrea, Davis and FHM Investments of interests in ETE, they may be deemed to beneficially own the limited partnership interests held by ETE, to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

(4) Each of Messrs. Mills and Cropper share Voting and Investment Power on a portion of their respective units with his/her spouse.

(5) Each of Messrs. Albin, Hersh, and Turner are representatives of or owners in entities owning interests in ETE and may be deemed to beneficially own the limited partnership interest held by ETE though any such deemed ownership is not depicted in the table.

(6) ETE owns all of the member interests of Energy Transfer Partners, L.L.C. and all of the Class A limited partner interests and Class B limited partner interests in Energy Transfer Partners GP, L.P. Energy Transfer Partners, L.L.C. is the General Partner of Energy Transfer Partners, GP, L.P. with a .01% General Partner interest. LE GP, LLC, the General Partner of ETE may be deemed to beneficially own the Common Units owned of record by ETE. The sole members of LE GP, LLC include Ray C. Davis, Kelcy L. Warren, Natural Gas Partners VI, L.P. (the NGP Fund) and Enterprise GP Holdings, L.P. G.F.W. Energy VI L.P. is the sole General Partner of the NGP Fund and G.F.W. VI, L.L.C. is the sole General Partner of G.F.W. Energy VI L.P. Messrs. Hersh and Albin, who constitute a majority of the members of G.F.W. VI, L.L.C., may also be deemed to share power to vote or to direct the vote and to dispose or to direct the disposition of the Common Units held by ETE.

(7) Energy Transfer Partners, L.P. indirectly owns 100% of the common stock of Heritage Holdings, Inc.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS,

AND DIRECTOR INDEPENDENCE

Our natural gas midstream operations secure compression services from third parties. Energy Transfer Technologies, Ltd. is one of the entities from which compression services are obtained. Energy Transfer Group, LLC is the General Partner of Energy Transfer Technologies, Ltd. These entities are collectively referred to as the ETG Entities . The ETG Entities were not acquired by us in conjunction with the January 2004 Energy Transfer Transactions. Our Chief Executive Officer, Kelcy L. Warren has an indirect ownership interest in, and two of our directors, Ted Collins, Jr. and Ray C. Davis, have an ownership interest in the ETG Entities. In addition, two of our directors, Ted Collins, Jr. and John W. McReynolds, serve on the Board of Directors of the ETG Entities. The terms of each arrangement to provide compression services are negotiated at an arms-length basis by management and are reviewed and approved by the Audit Committee. During fiscal year August 31, 2007, payments totaling $2.4 million were made to the ETG Entities for compression services provided to and utilized in our natural gas midstream operations.

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Under the terms of a Shared Services Agreement entered into in connection with the Energy Transfer Transactions, the ETG Entities lease office space and obtain related services from us. Payments totaling $0.2 million were paid by the ETG Entities during the fiscal year ended August 31, 2007.

On February 2, 2006 we entered into a shared services agreement effective upon the initial public offering of ETE. Under the terms of the shared services agreement, ETE will pay us an annual administrative fee of $0.5 million for the provision of various general and administrative services. The administrative fee may increase in the third year by the greater of 5% or the percentage increase in the consumer price index and may also increase if ETE later requires an increase in the level of general and administrative services. Fees recognized since the inception of this agreement were nominal.

On November 1, 2006, ETE purchased the remaining 50% of ETP s Incentive Distribution Rights from Energy Transfer Investments, L.P. (ETI). Also on November 1, 2006, we sold and issued to ETE approximately 26.1 million of our Class G Units for $1.2 billion (see Note 6 to our consolidated financial statements for additional information). After the November 1, 2006 transactions and the conversion of our Class F Units to Common Units (see Note 6 to our consolidated financial statements) ETE owns directly and indirectly the 2% General Partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights and 62,500,797 ETP Common Units.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following set forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered for the fiscal years ended August 31, 2007 and 2006:

	Year Ended August 31,	
	2007	2006
Audit fees (1)	$ 3,235,000	$ 3,368,139
Audit related fees		
Tax fees (2)	14,250	
All other fees (3)	60,000	5,000
Total	$ 3,309,250	$ 3,373,139

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the Securities and Exchange Commission and services related to the audit of our internal controls over financial reporting.

(2) Includes fees related to consultations regarding various publicly traded partnership income tax related practices.

(3) Includes fees related to responding to requests for copies of work papers and other materials and for the reimbursement of costs for a third-party training session provided to ETP employees.

Pursuant to the charter of the Audit Committee, they are responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP including audit services, audit-related services, tax services and other services, must be pre-approved by the Committee.

The Audit Committee reviews the external auditors proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our

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management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two fiscal years; and
- the rotation of the lead partner.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this Report:

(1) Financial Statements - see Index to Financial Statements appearing on page 82.

(2) Financial Statement Schedules - None.

(3) Exhibits - see Index to Exhibits set forth on page E-1.

SIGNATURES

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

ENERGY TRANSFER PARTNERS, L.P.

By Energy Transfer Partners GP, L.P,

its general partner.

By Energy Transfer Partners, L.L.C.,

its general partner

By: /s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer and officer duly authorized
to sign on behalf of the registrant

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

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	October 30, 2007
/s/ Brian J. Jennings Brian J. Jennings	Chief Financial Officer (Principal Financial and Accounting Officer)	October 30, 2007
/s/ Ray C. Davis Ray C. Davis	Director	October 30, 2007

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Signature	Title	Date
/s/ Bill W. Byrne Bill W. Byrne	Director	October 30, 2007
/s/ David R. Albin David R. Albin	Director	October 30, 2007
/s/ Kenneth A. Hersh Kenneth A. Hersh	Director	October 30, 2007
/s/ Paul E. Glaske Paul E. Glaske	Director	October 30, 2007
/s/ K. Rick Turner K. Rick Turner	Director	October 30, 2007
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	October 30, 2007
/s/ John W. McReynolds John W. McReynolds	Director	October 30, 2007
/s/ Michael K Grimm Michael K. Grimm	Director	October 30, 2007
/s/ John D. Harkey, Jr. John D. Harkey, Jr.	Director	October 30, 2007

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INDEX TO EXHIBITS

The exhibits listed on the following Exhibit Index are filed as part of this report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

	Exhibit Number	Description
(1)	3.1	Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(21)	3.1.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(21)	3.1.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(34)	3.1.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(35)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(46)	3.1.9	Amendment No. 9 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(45)	3.1.10	Amendment No. 10 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(1)	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(21)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(21)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(52)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(52)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(17)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.

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	Exhibit Number	Description
(21)	4.2	Unitholder Rights Agreement dated January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.
(27)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(28)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors names therein and Wachovia Bank, National Association, as trustee.
(37)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(29)	4.7	Registration Rights Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(39)	4.8	Joinder to Registration Rights Agreement, dated February 24, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(41)	4.9	Third Supplemental Indenture dated as of July 29, 2005 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(42)	4.10	Registration Rights Agreement, dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers thereto.
(43)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(43)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
(50)	4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(44)	4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(45)	4.15	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(53)	10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC as senior managing agents, and other lenders party hereto.
(1)	10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)	10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
(3)	10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
(5)	10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.

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		Exhibit Number	Description
(6)		10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(9)		10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)		10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(11)		10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(54)	*		Credit Agreement, dated as of October 5, 2007, by and among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, and certain other lenders party thereto.
(15)	**	10.6.3	Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
(26)	**	10.6.5	Form of Grant Agreement.
(52)	**	10.6.6	Amended and Restated 2004 Unit Plan.
(4)		10.16	Note Purchase Agreement dated as of November 19, 1997.
(5)		10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.
(6)		10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(7)		10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(8)		10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(11)		10.16.5	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(22)		10.16.6	Sixth Amendment Agreement dated as of November 18, 2003 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(8)		10.19	Note Purchase Agreement dated as of August 10, 2000.
(11)		10.19.1	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)		10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.
(22)		10.19.3	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(15)		10.26	Assignment, Conveyance and Assumption Agreement between U.S. Propane, L.P. and Heritage Holdings, Inc., as the former General Partner of Heritage Propane Partners, L.P. dated as of February 4, 2002.

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	Exhibit Number	Description
(15)	10.27	Assignment, Conveyance and Assumption Agreement between U.S. Propane, L.P. and Heritage Holdings, Inc., as the former General Partner of Heritage Operating, L.P., dated as of February 4, 2002.
(18)	10.28	Assignment for Contribution of Assets in Exchange for Partnership Interest dated December 9, 2002 amount V-1 Oil Co., the shareholders of V-1 Oil Co., Heritage Propane Partners, L.P. and Heritage Operating, L.P.
(19)	10.30	Acquisition Agreement dated November 6, 2003 among the owners of U.S. Propane, L.P. and U.S. Propane, L.L.C. and La Grange Energy, L.P.
(19)	10.31	Contribution Agreement dated November 6, 2003 among La Grange Energy, L.P. and Heritage Propane Partners, L.P. and U.S. Propane, L.P.
(20)	10.31.1	Amendment No. 1 dated December 7, 2003 to Contribution Agreement dated November 6, 2003 among La Grange Energy, L.P. and Heritage Propane Partners, L.P. and U.S. Propane, L.P.
(19)	10.32	Stock Purchase Agreement dated November 6, 2003 among the owners of Heritage Holdings, Inc. and Heritage Propane Partners, L.P.
(23)	10.35	Purchase and Sale Agreement between TXU Fuel Company and Energy Transfer Partners, L.P. dated April 25, 2004.
(23)	10.35.1	First Amendment to Purchase and Sale Agreement and Closing Agreement between TXU Fuel Company and Energy Transfer Partners, L.P. dated June 1, 2004.
(24)	10.36	Third Amended and Restated Credit Agreement among Heritage Operating L.P. and the Banks dated March 31, 2004.
(30)	10.40	Credit Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Fleet National Bank, as syndication agent, BNP Paribas and The Royal Bank of Scotland, PLC, as co-documentation agents, and other lenders party thereto.
(40)	10.40.1	First Amendment, dated as of February 24, 2005, to Credit Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Fleet National Bank, as syndication agent, BNP Paribas and The Royal Bank of Scotland, PLC, as co-documentation agents, and other lenders party thereto.
(31)	10.41	Guaranty, dated January 18, 2005, by the Subsidiary Guarantors in favor of Wachovia Bank, National Association, as the administrative agent for the lenders.
(40)	10.41.1	Guaranty Supplement dated February 24, 2005.
(32)	10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(33)	10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(36)	10.44	Loan Agreement, dated as of January 26, 2005 between La Grange Acquisition, L.P., as Borrower, and La Grange Energy, L.P., as Lender.
(50) **	10.45	Summary of Director Compensation.

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	Exhibit Number	Description
(47)	10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(48)	10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(49)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(53)	10.54	Fourth Amended and Restated Credit Agreement dated as of August 31, 2006 between and among Heritage Operating L.P., as the Borrower, and the Banks now or hereafter signatory parties hereto, as lenders Banks and Bank of Oklahoma, National Association as administrative agent and joint lead arranger for the Banks, JPMorgan Chase Bank, N.A., as syndication agent for the Banks, and J.P. Morgan Securities Inc., as joint lead arranger for the Banks.
(52)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(52)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(52)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(54)	21.1	List of Subsidiaries.
(*)	23.1	Consent of Grant Thornton LLP.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	99.1	Financial Statements of Energy Transfer Partners GP, L.P. as of August 31, 2007
(*)	99.2	Financial Statements of Energy Transfer Partners, L.L.C. as of August 31, 2007

* Filed herewith.
** Denotes a management contract or compensatory plan or arrangement.
(1) Incorporated by reference to the same numbered Exhibit to Registrant s Registration Statement on Form S-1, File No. 333-04018, filed with the Commission on June 21, 1996.
(2) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1996.

(3) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended February 28, 1997.
(4) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended May 31, 1998.
(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1998.
(6) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1999.
(7) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2000.
(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated August 23, 2000.
(9) File as Exhibit 10.16.3.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.
(11) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(13) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2001.
(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated February 4, 2002.
(18) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated January 6, 2003.
(19) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2003.
(20) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2003.
(21) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(22) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.

(23) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed June 14, 2004.
(24) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2004.
(25) Incorporated by reference to Annex A of the Registrant s Schedule 14A Proxy Statement filed May 18, 2004.
(26) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed November 1, 2004.
(27) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed January 19, 2005.
(28) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed January 19, 2005.
(29) Incorporated by reference to Exhibit 4.3 to the Registrant s Form 8-K filed January 19, 2005.
(30) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed January 19, 2005.
(31) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed January 19, 2005.
(32) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed February 1, 2005.
(33) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed February 1, 2005.
(34) Incorporated by reference to Exhibit 3.1.7 to the Registrant s Form 8-K filed March 16, 2005.
(35) Incorporated by reference to Exhibit 3.1.8 to the Registrant s Form 8-K filed February 9, 2006.
(36) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed March 17, 2005.
(37) Incorporated by reference to Exhibit 10.45 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(39) Incorporated by reference to Exhibit 10.39.1 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(40) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(41) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed August 2, 2005.
(42) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed August 2, 2005.
(43) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K/A for the year ended August 31, 2005.
(44) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed October 25, 2006.
(45) Incorporated by reference to Exhibit 3.1.10 to the Registrant s Form 8-K filed November 3, 2006.
(46) Incorporated by reference to Exhibit 3.1.9 to the Registrant s Form 8-K filed May 3, 2006.
(47) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed September 18, 2006.

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Index to Financial Statements

(48) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed September 18, 2006.
(49) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed September 18, 2006.
(50) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2006.
(51) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2007.
(52) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2007.
(53) Incorporated by reference to the same numbered Exhibit to the Registrant s 8-K filed on July 23, 2007.
(54) Incorporated by reference to Exhibit 10.1 to the Registrant s 8-K filed on October 9, 2007.