Energy Transfer Equity, L.P.
Form 10-K
March 02, 2009
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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 December 31, 2008

OR

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

Commission file number 1-32740

ENERGY TRANSFER EQUITY, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**30-0108820**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**

3738 Oak Lawn Avenue, Dallas, Texas 75219

(Address of principal executive offices and zip code)

Registrant s telephone number, including area code: (214) 981-0700

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

Title of each 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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one)

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

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

The aggregate market value as of June 30, 2008, of the registrant s Common Units held by non-affiliates of the registrant, based on the reported closing price of such units on the New York Stock Exchange on such date, was approximately $2,784,100,000. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At February 19, 2009, the registrant had 222,898,248 Common Units outstanding.

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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 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. 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
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.
Dth	Million British thermal units (dekatherm). 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.

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ITEM 1. BUSINESS

Overview

We are a publicly traded Delaware Limited Partnership, formerly known as La Grange Energy, L.P. Our Common Units are publicly traded on the New York Stock Exchange (NYSE) under the ticker symbol ETE . We were formed in September 2002 and completed our IPO of 24,150,000 Common Units in February 2006.

Unless the context requires otherwise, references to we, us, our, and ETE shall mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (ETP), Energy Transfer Partners G.P., L.P (ETP GP), the General Partner of ETP, and ETP GP s General Partner, Energy Transfer Partners, L.L.C. (ETP LLC). References to the Parent Company shall mean Energy Transfer Equity, L.P. on a stand-alone basis.

The Parent Company s only cash generating assets are its direct and indirect investments in limited partner and general partner interests in ETP. The Parent Company s direct and indirect ownership of ETP consist of approximately 62.5 million Common Units, the 2% General Partner interests and 100% of the Incentive Distribution Rights. The Parent Company s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of ETP or the Operating Partnerships.

Currently, the Parent Company s business operations are conducted only through ETP s wholly-owned subsidiary operating partnerships (collectively referred to as the Operating Partnerships). The activities in which we are engaged, all of which are in the United States, and 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).

In order to fully understand the financial condition and results of operations of the Parent Company on a stand-alone basis, we have included herein discussions of Parent Company matters apart from those of our consolidated group.

Significant 2008 Achievements

Our significant 2008 achievements included the following, as discussed in more detail herein:

- The Parent Company received distributions from ETP of $236.3 million, $4.8 million and $305.1 million related to its limited partner interests, general partner interests and Incentive Distribution Rights, respectively.
- On a consolidated basis, we had revenues of approximately $9.29 billion, operating income of approximately $1.10 billion and net income of approximately $375.0 million. See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Continued our expansion initiative, completing projects totaling more than 400 miles of large diameter pipeline ranging from 36 inches to 42 inches with approximately 3.9 Bcf/d of natural gas transportation capacity during 2008. These completed pipeline construction projects include:

- 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.

- The 36-inch Paris Loop pipeline expansion project in North Texas, a 135-mile pipeline connecting our existing pipelines in the Barnett Shale region to our Texoma pipeline in Lamar County, Texas. In the second quarter of 2009, the Paris Loop will connect to the 500-mile Midcontinent Express pipeline.

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Expansion of our Cleburne to Carthage pipeline (the Carthage Loop) from the Texoma pipeline interconnect to the Carthage Hub through the installation of 32 miles of 42-inch pipeline.

The 36-inch Maypearl to Malone pipeline which provides a link to an additional 600 MMcf/d of capacity out of the Barnett Shale region.

The 36-inch San Juan Loop pipeline. The San Juan Loop is the first phase of the previously announced Phoenix Expansion project that also includes the construction of a new 260-mile Phoenix Lateral pipeline designed to serve both residential and industrial customers in the high-growth Phoenix market. The Phoenix Lateral was completed in February of 2009.

Entered into an agreement for a 50/50 joint development of the Fayetteville Express pipeline, as discussed below under Recent Developments .

Began construction of the Midcontinent Express pipeline, 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. The pipeline will have an initial capacity of 1.5 Bcf/d, all of which capacity has been committed pursuant to predominantly 10-year firm transportation contracts with shippers and is expected to be completed and in service through Perryville, Louisiana in the second quarter of 2009. The pipeline has also received long-term transportation contracts related to an additional 0.3 Bcf/d of capacity that is planned to be added through the utilization of additional compression. Midcontinent Express pipeline is a 50/50 joint development with KMP.

Announced our plans to construct the Texas Independence pipeline, a 160-mile, 42-inch project which will connect to our Carthage Loop. This pipeline is expected to be completed in the third quarter of 2009.

Completed expansion of the natural gas processing plant in Godley, Texas, increasing the plant capacity to approximately 500 MMcf/d.

Completed several financing transactions despite challenging market conditions in 2008, including the issuance of $1.5 billion and $600.0 million of ETP Senior Notes in March 2008 and December 2008, respectively, and ETP s issuance of 7,750,000 ETP Common Units in July 2008. In addition, ETP subsequently raised $225.9 million in proceeds from the issuance of 6,900,000 ETP Common Units in January 2009.

Recent Developments

ETP Enogex Partners LLC

In September 2008, we entered into an agreement with OGE Energy Corp. (OGE) to form a joint venture entity, ETP Enogex Partners LLC (ETP Enogex Partners), to which OGE would contribute its Enogex midstream business and we would contribute our 100% equity interest in Transwestern, our 50% equity interest in Midcontinent Express Pipeline, LLC (MEP), the entity formed to own and operate the Midcontinent Express pipeline, and our 100% equity interest in ETC Canyon Pipeline, LLC, which we refer to as ETC Canyon Pipeline, which owns and operates the Canyon Gathering System. Subsequent to entering into this agreement, conditions in the credit markets deteriorated and the parties were not able to obtain financing on favorable terms. On February 12, 2009, ETP and OGE agreed to terminate the agreement to form a joint venture.

Fayetteville Express Pipeline LLC

In October 2008, we entered into an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 187-mile pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. Fayetteville Express Pipeline LLC (FEP), the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the FERC s National Environmental Policy Act (NEPA) pre-filing review process of the Federal Energy Regulatory Commission (FERC) in November 2008. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the pipeline project is expected to be in service by early 2011. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (NGPL) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi, and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Knight, Inc. (formerly known as Kinder Morgan, Inc.). Knight owns the general partner of KMP. Pursuant to our agreement with KMP related to this project, we and KMP are each obligated to fund 50% of the equity necessary to construct the project.

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Tiger Pipeline

On January 27, 2009 ETP announced that we had entered into an agreement with Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary of Chesapeake Energy Corporation (Chesapeake) to construct a 178-mile 42-inch interstate natural gas pipeline (Tiger pipeline). The project will connect to ETP s dual 42-inch pipeline system near Carthage, Texas extend through the heart of the Haynesville Shale and end near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana.

The Tiger pipeline is anticipated to have an initial throughput capacity of at least 1.25 Bcf/d, which capacity may be increased up to 2.0 Bcf/d based on the results of an open season. The agreement with Chesapeake provides for a 15-year commitment for firm transportation capacity of approximately 1.0 Bcf/d. The pipeline project is anticipated to cost between $1.0 billion and $1.2 billion, depending on the final throughput capacity design, with such costs to be incurred over a three-year period. Pending necessary regulatory approvals, the Tiger pipeline is expected to be in service in the first half of 2011.

ETP Operations

Segment Overview and Business Description

Our segments and business are as described below. See Notes 1 and 15 to our consolidated financial statements for additional financial information about our segments for the year ended December 31, 2008.

Natural Gas Operations

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

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Midstream

Southeast Texas System

- 5,000 miles of natural gas pipeline
- 1 natural gas processing plant (the La Grange plant) with aggregate capacity of 240 MMcf/d
- 11 natural gas treating facilities with aggregate capacity of 1.3 Bcf/d
- 4 natural gas conditioning facilities with aggregate capacity of 670 MMcf/d

North Texas System

- 160 miles of natural gas pipeline
- 1 natural gas processing plant (the Godley plant) with aggregate capacity of 500 MMcf/d
- 1 natural gas conditioning facility with capacity of 100 MMcf/d

Canyon Gathering System

- 1,360 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 4.1 Bcf/d
- 2,680 miles of natural gas pipeline
- 2 storage facilities with 12.4 Bcf of total working gas capacity

Oasis pipeline

Capacity of 1.2 Bcf/d

600 miles of natural gas pipeline

Connects Waha to Katy market hubs

Houston pipeline system (HPL System)

Capacity of 5.5 Bcf/d

4,200 miles of natural gas pipeline

Bammel storage facility with 62 Bcf of total working gas capacity

East Texas pipeline

Capacity of 2.0 Bcf/d

320 miles of natural gas pipeline

Interstate Transportation Pipelines

Transwestern pipeline

Capacity of 2.1 Bcf/d

2,700 miles of interstate natural gas pipeline

Phoenix lateral pipeline 260 miles of 36-inch and 42-inch pipeline with initial planned capacity of 500 MMcf/d was completed in February 2009

Midcontinent Express pipeline

Initial planned capacity of 1.5 Bcf/d (expected to be in service in the second quarter of 2009)

Planned capacity expansion of 0.3 Bcf/d (expected to be in service in the fourth quarter of 2010)

500 miles of interstate natural gas pipeline

50/50 joint venture with KMP

Fayetteville Express pipeline

Initial planned capacity of 2.0 Bcf/d (expected to be in service in the first quarter of 2011)

187 miles of interstate natural gas pipeline

50/50 joint venture with KMP

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Tiger pipeline

Initial planned capacity of 1.25 Bcf/d (expected to be in service in the first half of 2011)

178 miles of interstate natural gas pipeline

Midstream Segment

Our midstream business owns and operates approximately 6,700 miles of in service natural gas gathering pipelines, three natural gas processing plants, eleven natural gas treating facilities, and eleven 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 and New Mexico, 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 14% of our total consolidated operating income for the year ended December 31, 2008. 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. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

The following is a brief description of the various components of our midstream segment:

The Southeast Texas System is a 5,000-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, eleven treating facilities and four conditioning facilities. This system is connected to the Katy Hub through the 320-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 eleven treating facilities have an aggregate capacity of 1.3 Bcf/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 four conditioning facilities have an aggregate capacity of 670 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 is 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 processes 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 500 MMcf/d and a conditioning facility with approximately 100 MMcf/d of processing capacity. .

The Canyon Gathering System consists of approximately 1,360 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 300 MMcf/d from 1,400 wells and is connected to five major pipeline systems.

The midstream segment also includes our interests in various midstream assets located in Texas, New Mexico and Louisiana, with a combined capacity of approximately 470 MMcf/d.

Marketing operations, 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.

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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.

Intrastate Transportation and Storage Segment

Our intrastate transportation and storage business owns and operates approximately 7,800 miles of natural gas transportation pipelines and three natural gas storage 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.

Our intrastate transportation and storage operations accounted for approximately 65% of our total consolidated operating income for the year ended December 31, 2008. 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 marketing operations) 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.

The following is a brief description of the various components of our intrastate transportation and storage segment:

The ET Fuel System, which serves some of the most active drilling areas in the United States, is comprised of approximately 2,680 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 4.1 Bcf/d.

The ET Fuel System also includes 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, 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 is primarily a 36-inch diameter, 600-mile natural gas pipeline that directly connects the Waha Hub to the Katy Hub. 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;

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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 4,200 miles of intrastate natural gas pipeline with an aggregate capacity of 5.5 Bcf/d, the underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from south Texas, the Gulf Coast 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 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 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 facility 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.

During the third quarter of 2008, we completed the expansion of our Cleburne to Carthage pipeline from the Texoma pipeline interconnect to the Carthage Hub through the installation of 32 miles of 42-inch pipeline. This expansion, which we refer to as the Carthage Loop, added 500 MMcf/d of pipeline capacity from Cleburne to the Carthage Hub.

The East Texas pipeline is a 320-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 2.0 Bcf/d with the addition of the Grimes County Compressor Station.

Interstate Transportation Segment

Our interstate transportation segment accounted for approximately 11% of our total consolidated operating income for the year ended December 31, 2008. 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.

The following is a brief description of the various components of our interstate transportation segment:

The Transwestern pipeline is an open-access natural gas interstate pipeline extending 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. Including the recently completed projects listed below, Transwestern comprises approximately 2,700 miles of pipeline with a capacity of 2.1 Bcf/d. 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 the Federal Energy Regulatory Commission (FERC). The operating results for Transwestern are included in our results on a consolidated basis as of the acquisition date (December 1, 2006).

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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. The Phoenix project, as filed with the 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. The San Juan Lateral portion of the project was placed in service effective July 2008. On February 20, 2009, FERC authorized Transwestern to commence service on the Phoenix lateral.

We are currently constructing, through a 50/50 joint venture arrangement with KMP, the Midcontinent Express pipeline, an approximately 500-mile interstate natural gas pipeline. The Midcontinent Express pipeline 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, which transports natural gas to the significant natural gas markets in the northeast portion of the United States. The pipeline will have an initial capacity of 1.5 Bcf/d, all of which capacity has been committed pursuant to predominantly 10-year firm transportation contracts with shippers. The pipeline has also received long-term transportation contracts related to an additional 0.3 Bcf/d of capacity that is planned to be added through the utilization of additional compression. Mobilization for construction of this pipeline commenced in September 2008, following FERC approval. The first phase of the pipeline is expected to be in service by the second quarter of 2009 and the second phase of the pipeline is expected to be in service by the third quarter of 2009. Certain regulatory approvals are still pending with respect to the expansion and interim service of Midcontinent Express pipeline. We account for this joint venture using the equity method, as further discussed in our consolidated financial statements.

In October 2008, we entered into an agreement with KMP for a 50/50 joint development of Fayetteville Express pipeline, an approximately 187-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. FEP, the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the FERC s NEPA pre-filing review process in November 2008. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the pipeline project is expected to be in service by early 2011. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with NGPL in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi, and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Knight, Inc. Knight, Inc. owns the general partner of KMP. Pursuant to our agreement with KMP related to this project, we and KMP are each obligated to fund 50% of the equity necessary to construct the project. We account for this joint venture using the equity method, as further discussed in our consolidated financial statements.

On January 27, 2009 we announced that we had entered into an agreement with Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary of Chesapeake to construct the Tiger pipeline, a 178-mile 42-inch interstate natural gas pipeline. The Tiger pipeline will connect to ETP s dual 42-inch pipeline system near Carthage, Texas, extend through the heart of the Haynesville Shale and end near Delhi, Louisiana, and interconnect with at least seven interstate pipelines at various points in Louisiana.

The Tiger pipeline is anticipated to have an initial throughput capacity of at least 1.25 Bcf/d, which capacity may be increased up to 2.0 Bcf/d based on the results of an open season. The agreement with Chesapeake provides for a 15-year commitment for firm transportation capacity of approximately 1.0 Bcf/d. The pipeline project is anticipated to cost between $1.0 billion and $1.2 billion, depending on the final throughput capacity design, with such costs to be incurred over a three-year period. Pending necessary regulatory approvals, the Tiger pipeline is expected to be in service in the first half of 2011.

Retail Propane Segment

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 10% of our total consolidated operating income for the year ended December 31, 2008. 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 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

The Parent Company Business Strategy

Our current primary business objective is to increase our cash distributions to our Unitholders by actively assisting ETP in executing its business strategy by assisting in identifying, evaluating, and pursuing acquisitions and growth opportunities. In general, we expect that we will allow ETP the first opportunity to pursue any acquisition or internal growth project that may be presented to us which is within the scope of ETP s operations or business strategy. In the future, we may also support the growth of ETP through the use of our capital resources, which could involve loans, capital contributions or other forms of credit support to ETP. This funding could be used for the acquisition by ETP of a business or asset or for an internal growth project. In addition, the availability of this capital could assist ETP in arranging financing for a project, reducing its financing costs or otherwise supporting a merger or acquisition transaction.

ETP s Business Strategy and Strengths

ETP s primary objective is to increase Unitholder distributions and the value of its Common Units. We believe ETP has 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.

ETP intends 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 ETP Common Unit. We believe that by pursuing independent operating and growth strategies for ETP s natural gas operations and retail propane business, we will be best positioned to achieve our objectives.

We expect that acquisitions in natural gas operations will be the primary focus of our acquisition strategy going forward, as evidenced by the Transwestern pipeline and Canyon Gathering System acquisitions, although we also expect to continue to pursue complementary propane acquisitions. 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 significant number of completed natural gas pipeline projects as well as our recently announced pipeline 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:

We believe that the size and scope of our operations, our stable asset base and cash flow profile, and our investment grade status will be significant positive factors in our efforts to obtain new debt or equity financing in light of current market conditions, as evidenced by ETP s public debt offering in December 2008 of $600.0 million aggregate principal amount of 9.70% Senior Notes due 2019 and ETP s public equity offering in January 2009 of 6,900,000 ETP Common Units which provided us with aggregate net proceeds of approximately $821.9 million. See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations Financing and Sources of Liquidity .

Our experienced management team has an established reputation as highly effective, strategic operators within our operating segments. In addition, our management team is motivated to effectively and efficiently manage our business operations through performance-based incentive compensation programs and has a substantial equity ownership in us.

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.

Increase cash flow from fee-based businesses. We intend to seek to increase the percentage of our midstream and transportation 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.

Natural Gas Operations Business Strengths

Our assets provide marketing flexibility through our access to numerous markets and customers. Through the combination of strategic acquisitions and substantial investments in internal growth projects and expansions, we have engineered our pipeline system to be well-positioned to service major North American natural gas producing basins. Our assets provide 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 assets are tied directly or indirectly to a number of major power generation facilities in Texas as well as several industrial and utility end-users. With the acquisition of the ET Fuel System in June 2004, the HPL System acquisition in January 2005, and the completion of several intrastate pipeline construction projects in Texas over the last three years, 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 an expansion of the Cleburne to Carthage pipeline and the completion of the Southern Shale pipeline, the Southeast Bossier pipeline, the Paris Loop pipeline and the Maypearl to Malone pipeline provides producers with firm capacity out of the Barnett Shale, the Bossier Sands, the Permian Basin, and other major producing areas to all major market hubs in Texas and numerous interstate pipelines. We also provide our customers with additional firm access to west coast and the Phoenix markets with the acquisition of the Transwestern pipeline and the completion of the Phoenix lateral.

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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 including north Texas (Barnett Shale), east Texas (Bossier), west Texas (Permian Basin), the Texas Gulf Coast, the Texas Panhandle, and the Rocky Mountains.

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 0.6 Bcf/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

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.

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.

Maintain low-cost, decentralized operations. We focus on controlling costs, and we attribute our low overhead costs primarily to our decentralized structure.

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.

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 operations are located in rural areas where natural gas is not readily available.

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.

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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 data released in December 2008 by the Energy Information Administration, or the EIA, total domestic consumption of natural gas is expected to remain steady through 2030, with average annual consumption of 23.6 Tcf during that period, compared to 2008 consumption of 23.4 Tcf. The industrial and electricity generation sectors currently account for more than half of natural gas usage in the United States.

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

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

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is 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

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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 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.

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. In particular, our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas and NGLs have fallen dramatically since July 2008. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells.

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 December 31, 2008, none of our customers individually accounted for more than 10% of our midstream, intrastate transportation and storage and interstate segment revenues.

Regulation

Regulation by Federal Energy Regulatory Commission (FERC) of Interstate Natural Gas Pipelines. FERC has broad regulatory authority over the business and operations 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 includes natural gas pipeline transmission (forwardhauls and backhauls), storage, and other services. The Transwestern pipeline transports natural gas in interstate commerce and thus qualifies as a natural gas company under the NGA subject to FERC s regulatory jurisdiction. We also hold interests in two joint venture projects involving the construction and operation of interstate pipelines: Midcontinent Express pipeline and Fayetteville Express pipeline. When completed and placed into operation, these pipeline systems will also be NGA-jurisdictional interstate transportation systems subject to the FERC s broad regulatory oversight.

FERC s NGA authority includes the power to regulate:

- the certification and construction of new facilities;
- the review and approval of cost-based transportation rates;
- the types of services that our regulated assets are permitted to perform;

the terms and conditions associated with these services;

the extension or abandonment of services and facilities;

the maintenance of accounts and records;

the acquisition and disposition of facilities; and the initiation and discontinuation of services.

Under the NGA, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

In September 2006, Transwestern filed revised tariff sheets under section 4 of the NGA proposing a general rate increase to be effective on November 1, 2006. In April 2007, FERC approved a Stipulation and Agreement of Settlement (Stipulation and Agreement) that resolved primary components of the rate case. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. As a part of the Stipulation and Agreement, no settling party shall seek, solicit or financially support a change or challenge to any effective provision of the Stipulation and Agreement during the term of the Stipulation and Agreement. Transwestern is not required to file a new rate case until October 1, 2011.

Rates to be charged on the Midcontinent Express pipeline will largely be governed by long-term negotiated rate agreements, an arrangement approved by FERC in its July 25, 2008 order granting Midcontinent Express pipeline the certificate of public convenience and necessity to build, own and operate these facilities. In the certificate order, FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates. The application for a certificate of public convenience and necessity to construct the Fayetteville Express pipeline project has not yet been filed with FERC, hence the rates to be charged for services provided on that facility have not yet been established.

The rates to be charged by NGA-jurisdictional natural gas companies are generally required to be on file with FERC in FERC-approved tariffs. Most natural gas companies are authorized to offer discounts from their FERC-approved maximum just and reasonable rates when competition warrants such discounts. Natural gas companies are also generally permitted to offer negotiated rates different from rates established in their tariff if, among other requirements, such companies tariffs offer a cost-based recourse rate available to a prospective shipper as an alternative to the negotiated rate. Natural gas companies must make offers of rate discounts and negotiated rates on a basis that is not unduly discriminatory. Existing tariff rates may be challenged by complaint and if found unjust and unreasonable may be altered on a prospective basis by FERC. Rate increases proposed by the interstate natural gas company may be challenged by protest or by FERC itself, and if such proposed rate increases are found unjust and unreasonable may be rejected by FERC in whole or in part. Any successful complaint or protest against the FERC-approved rates of our interstate pipelines could have a prospective impact on our revenues associated with providing interstate transmission services. 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.

Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. Pursuant to FERC s rules promulgated under this statutory directive, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to Commission jurisdiction: (1) to defraud using any device, scheme or artifice; (2) to make any untrue statement of material fact or omit a material fact; or (3) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission, or the CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. With regard to our physical purchases and sales of natural gas, NGLs or other energy commodities; our gathering or transportation of these energy commodities; and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Failure to comply with the NGA, the Energy Policy Act of 2005 and the other federal laws and regulations governing our operations and business activities can result in the imposition of administrative, civil and criminal remedies.

Intrastate Natural Gas Regulation. Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act (NGPA). The NGPA 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 intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility s statement of operating conditions are also 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.

FERC has adopted new market-monitoring and annual reporting regulations, which regulations are applicable to many intrastate pipelines as well as other entities that are otherwise not subject to FERC s NGA jurisdiction. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve FERC s ability to assess market forces and detect market manipulation. FERC has also proposed to require certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information. These posting requirements are not administratively final, thus it is not known with certainty the precise form these requirements will ultimately take. Depending upon the breadth of FERC s final rules, these regulations could subject us to further costs and administrative burdens.

Our intrastate natural gas operations in Texas are also 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.

Sales of Natural Gas and NGLs. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The price at which we sell NGLs is not subject to federal or state regulation.

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. 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 regulatory changes 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 in a manner that is materially different from 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, Louisiana, Colorado and Utah 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.

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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. In Louisiana, our Chalkley System is regulated as an intrastate transporter, and the Louisiana 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. 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 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.

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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 6.5% 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.

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 55% were to residential customers, 30% were to industrial, commercial and agricultural customers, and 15% were to other retail users. Sales to residential customers in the year ended December 31, 2008 accounted for 55% of total retail gallons sold but accounted for approximately 70% 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 21% of our gross profit from propane sales for the year ended December 31, 2008, with all other retail users accounting for 9%. 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 year ended December 31, 2008, Enterprise Products Operating L.P. (Enterprise) and Targa Liquids (Targa) provided approximately 50.7%, and 15.0% 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 40.6% non-controlling equity interest in LE GP, LLC, the general partner of ETE (LE GP). 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, we have a seven-year propane purchase agreement with M.P. Oils, Ltd. (see Note 10 to our consolidated financial statements), which provided 14.9% of our combined total propane supply during the year ended December 31, 2008.

We believe that if supplies from Enterprise, Targa or M.P. Oils, Ltd. were interrupted, we would be able to secure adequate propane supplies from other sources without a material disruption of our operations. No other single supplier provided more than 10% of our total domestic propane supply during the year ended December 31, 2008. 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 ETP s supply agreement and the agreement with M.P. Oils, Ltd., 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.

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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 how 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. 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. We have implemented environmental programs and policies designed to reduce potential liability and costs under applicable environmental laws and regulations.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Changes in environmental laws and regulations that result in more stringent waste handling, storage, transport, disposal, or remediation requirements will increase our cost for performing those activities, and if those increases are sufficiently large, they 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. One class of responsible persons is the current owners or operators of contaminated property, even if the contamination arose as a result of historical operations conducted by previous, unaffiliated occupants of the property. Under CERCLA, 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 also 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 certain types of non-excluded 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 were 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 United States 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 December 31, 2008 an accrual of $13.3 million was recorded in our consolidated balance sheet as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities including certain matters assumed in connection with our acquisition of the HPL System, the Transwestern acquisition, potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors and the predecessor owner s share of certain environmental liabilities of ETC OLP.

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 contamination by polychlorinated biphenyls (PCBs), and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is approximately $9.1 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern continues to incur certain costs related to PCBs that could migrate through its pipelines 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 $0.8 million for the period since acquisition. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at December 31, 2008. 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 the EPA 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 federal 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, because the Texas Commission on Environmental Quality is currently developing a plan to respond to the re-designation of the Houston area from a moderate to a severe ozone non-attainment area, and later it will develop another plan to address the recent change in the ozone standard from 0.08 ppm to 0.075 ppm. We expect these efforts will result in the adoption of new regulations that may require additional NOx emissions reductions.

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In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth s atmosphere, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider, legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. These cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants that emit more greenhouse gases than permitted by these programs, to acquire emission allowances from other businesses that emit greenhouse gases at levels lower than the limits specified by these programs and then surrender these allowances as a credit against such emissions. Depending on the particular program, we could be required to purchase and surrender such emission allowances, either for greenhouse gas emissions resulting from our operations (*e.g.*, compressor stations) or from the combustion of fuels (*e.g.*, natural gas) that we process.

Also, as a result of the United States Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases, including carbon dioxide, fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court s decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could also have an adverse affect on our cost of doing business and demand for the natural gas we process and transport.

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. Through December 31, 2008, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2009. Through December 31, 2008, a total of $16.4 million of capital costs and $12.7 million of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through December 31, 2008, a total of $6.9 million of capital costs and $0.4 million of operating and maintenance costs have been incurred for pipeline integrity costs 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.

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 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 February 6, 2009, we employed 1,153 people to operate our natural gas operation segments. We employ 4,277 full-time employees to operate our propane segments. Of the propane employees, 84 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 file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the Securities and Exchange Commission (SEC). 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, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. 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, http://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. Information contained on our website is not part of this report.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. These are not all the risk we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Inherent in an Investment in Us:

Our only assets are our partnership interests, including the incentive distribution rights, in ETP and, therefore, our cash flow is dependent upon the ability of ETP to make distributions in respect of those partnership interests.

The amount of cash that ETP can distribute to its partners, including us, each quarter depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter and will depend on, among other things:

- the amount of natural gas transported through ETP s transportation pipelines and gathering systems;
- the level of throughput in its processing and treating operations;
- the fees it charges and the margins it realizes for its gathering, treating, processing, storage and transportation services;
- the price of natural gas;
- the relationship between natural gas and NGL prices;

the weather in its operating areas;

the cost of the propane it buys for resale and the prices it receives for its propane;

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

the level of its operating costs;

prevailing economic conditions; and

the level of ETP s hedging activities.

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

the level of capital expenditures it makes;

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;

its debt service requirements;

fluctuations in its working capital needs;

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

its ability to access capital markets;

restrictions on distributions contained in its debt agreements; and

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

Because of these factors, we cannot guarantee that ETP will have sufficient available cash to pay a specific level of cash distributions to its partners.

Furthermore, you should be aware that the amount of cash that ETP has available for distribution depends primarily upon its 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, ETP may make cash distributions during periods when it records net losses and may not make cash distributions during periods when it records net income. Please read Risks Related to Energy Transfer Partners Business included in this Item 1A for a discussion of further risks affecting ETP s ability to generate distributable cash flow.

We may not have sufficient cash to pay distributions at our current quarterly distribution level or to increase distributions.

The source of our earnings and cash flow is cash distributions from ETP. Therefore, the amount of distributions we are currently able to make to our Unitholders may fluctuate based on the level of distributions ETP makes to its partners. ETP may not be able to continue to make quarterly distributions at its current level or increase its quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our Unitholders if ETP increases or decreases distributions to us, the timing and amount of such increased or decreased distributions, if any, will not necessarily be comparable to the timing and amount of the increase or decrease in distributions made by ETP to us.

Our ability to distribute cash received from ETP to our Unitholders is limited by a number of factors, including:

- interest expense and principal payments on our indebtedness;
- restrictions on distributions contained in any current or future debt agreements;
- our general and administrative expenses;
- expenses of our subsidiaries other than ETP, including tax liabilities of our corporate subsidiaries, if any;
- capital contributions to maintain our 2% general partner interest in ETP as required by the partnership agreement of ETP upon the issuance of additional partnership securities by ETP; and
- reserves our General Partner believes prudent for us to maintain for the proper conduct of our business or to provide for future distributions.

We cannot guarantee that in the future we will be able to pay distributions or that any distributions we do make will be at or above our current quarterly distribution. The actual amount of cash that is available for distribution to our Unitholders will depend on numerous factors, many of which are beyond our control or the control of our General Partner.

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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, our Unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Our Unitholders do not have the ability to elect our general partner or the officers or directors of our general partner.

Furthermore, if our Unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least 66 2/3% of our outstanding units. Because affiliates of our general partner (including Enterprise GP Holdings L.P.) own 39,768,401 Common Units, representing approximately 18% of our outstanding Common Units, it will be particularly difficult for our general partner to be removed without the consent of such affiliates. As a result, the price at which our Common Units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

A reduction in ETP s distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Our direct and indirect ownership of 100% of the incentive distribution rights in ETP (50% prior to November 1, 2006), through our ownership of equity interests in Energy Transfer Partners GP, the holder of the incentive distribution rights, entitles us to receive our pro rata share of specified percentages of total cash distributions made by ETP as it reaches established target cash distribution levels. The amount of the cash distributions that we received from ETP during our fiscal year 2006 related to our ownership interest in the incentive distribution rights has increased at a more rapid rate than the amount of the cash distributions related to our 2% General Partner interest in ETP and our ETP Common Units. We currently receive our pro rata share of cash distributions from ETP based on the highest incremental percentage, 48%, to which Energy Transfer Partners GP is entitled pursuant to its incentive distribution rights in ETP. A decrease in the amount of distributions by ETP to less than \$0.4125 per Common Unit per quarter would reduce Energy Transfer Partners GP s percentage of the incremental cash distributions above \$0.3175 per Common Unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from ETP would have the effect of disproportionately reducing the amount of all distributions that we receive from ETP based on our ownership interest in the incentive distribution rights in ETP as compared to cash distributions we receive from ETP on our 2% General Partner interest in ETP and our ETP Common Units.

Neither we nor ETP will be prohibited from competing with each other.

Neither our Partnership Agreement nor the Partnership Agreement of ETP prohibits us from owning assets or engaging in businesses that compete directly or indirectly with ETP or prohibit ETP from owning assets or engaging in businesses that compete directly or indirectly with us, except that ETP s Partnership Agreement prohibits us from engaging in the retail propane business in the United States. In addition, we may acquire, construct or dispose of any assets in the future without any obligation to offer ETP the opportunity to purchase or construct any of those assets, and ETP may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

Our consolidated debt level and our debt agreements and those of our subsidiaries may limit our ability to make distributions to Unitholders and may limit the distributions we receive from ETP and our future financial and operating flexibility.

As of December 31, 2008, we had approximately \$7.24 billion of consolidated debt outstanding. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our and ETP s 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 and ETP s 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;

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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 to pay distributions. We are required to measure these financial tests and covenants quarterly and, as of December 31, 2008, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

Completion of pipeline expansion projects will require significant amounts of debt and equity financing which may not be available to ETP on acceptable terms, or at all.

ETP plans to fund its expansion capital expenditures, including any future pipeline expansion projects ETP may undertake, with proceeds from sales of ETP s debt and equity securities and borrowings under ETP s revolving credit facility; however, ETP cannot be certain that it will be able to issue ETP s debt and equity securities on terms satisfactory to ETP, or at all. In addition, ETP may be unable to obtain adequate funding under its current revolving credit facility because ETP s lending counterparties may be unwilling or unable to meet their funding obligations. If ETP is unable to finance its expansion projects as expected, ETP could be required to seek alternative financing, the terms of which may not be attractive to ETP, or to revise or cancel its expansion plans.

As of December 31, 2008, ETP had approximately $5.66 billion of consolidated debt outstanding. A significant increase in ETP s indebtedness that is proportionately greater than ETP s issuances of equity could negatively impact ETP s credit ratings or its ability to remain in compliance with the financial covenants under ETP s revolving credit agreement, which could have a material adverse effect on ETP s financial condition, results of operations and cash flows.

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 December 31, 2008, we had approximately $7.24 billion of consolidated debt, of which approximately $4.76 billion was at fixed interest rates and approximately $2.48 billion was at variable interest rates. We have entered interest rate swaps for a total notional amount of $2.13 billion, resulting in a net amount of $0.35 billion of variable-rate debt at December 31, 2008. We may enter into additional interest rate swap arrangements. As a result, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates. During the three months ended December 31, 2008, ETP entered into forward starting interest rate swaps with a notional amount of $500.0 million for a forecasted debt issuance by the end of 2009. These swaps were not designated as cash flow hedges; therefore, changes in interest rates could adversely affect ETP s and our results of operations until the forecasted debt is issued and could require a cash payment upon settlement.

Increases in interest rates may cause a corresponding decline in demand for yield-based equity investments such as our Common Units.

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 indirect owner of our General Partner may be factors in credit evaluations of us as a master limited partnership due to the significant influence of our General Partner and its indirect owner over our business activities, including our cash distributions, 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 us to service their indebtedness.

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We may issue an unlimited number of limited partner interests without the consent of our Unitholders, which will dilute your ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

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 by us will have the following effects:

- our Unitholders current proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each Common Unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding Common Unit may be diminished; and
- the market price of our Common Units may decline.

In addition, ETP may sell an unlimited number of limited partner interests without the consent of its Unitholders which will dilute existing interests of its Unitholders, including us. The issuance of additional Common Units or other equity securities by ETP will have essentially the same effects as detailed above.

The market price of our Common Units could be adversely affected by sales of substantial amounts of our units in the public markets, including sales by our existing Unitholders.

Sales by any of our existing Unitholders of a substantial number of our units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

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

Our General Partner may transfer its General Partner interest in us to a third party in a merger or in a sale of its equity securities without the consent of our Unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the members of our General Partner to sell or transfer all or part of their ownership interest in our General Partner to a third party. The new owner or owners of our General Partner would then be in a position to replace the directors and officers of our General Partner and control the decisions made and actions taken by the board of directors and officers.

Our General Partner has only one executive officer, and we are dependent on third parties, including key personnel of ETP under a shared services agreement, to provide the financial, accounting, administrative and legal services necessary to operate our business.

John W. McReynolds, the President and Chief Financial Officer of our General Partner, is the only executive officer charged with managing our business other than through our shared services agreement with ETP. We do not currently have a plan for identifying a successor to Mr. McReynolds in the event that he retires, dies or becomes disabled. If Mr. McReynolds ceases to serve as the President and Chief Financial Officer of our General Partner for any reason, we would be without executive management other than through our shared services agreement with ETP until one or more new executive officers are selected by the board of directors of our General Partner. As a consequence, the loss of Mr. McReynolds services could have a material negative impact on the management of our business.

Moreover, we rely on the services of key personnel of ETP, including the ongoing involvement and continued leadership of Kelcy L. Warren, one of the founders of ETP s midstream business, as well as other key members of ETP s management team such as Mackie McCrea, President and Chief Operating Officer, and William G. Powers, President of Propane Operations. Mr. Warren has been integral to the success of ETP s midstream and intrastate transportation and storage businesses because of his ability to identify and develop strategic business opportunities. Losing his leadership could make it difficult for ETP to identify internal growth projects and accretive acquisitions, which could have a material adverse effect on ETP s ability to increase the cash distributions paid on its partnership interests.

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ETP s executive officers that provide services to us pursuant to a shared services agreement allocate their time between us and ETP. To the extent that these officers face conflicts regarding the allocation of their time, we may not receive the level of attention from them that the management of our business requires. If ETP is unable to provide us with a sufficient number of personnel with the appropriate level of technical accounting and financial expertise, our internal accounting controls could be adversely impacted.

An increase in interest rates may cause the market price of our units to decline.

Like all equity investments, an investment in our units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our units to decline.

Your liability as a limited partner may not be limited, and our Unitholders may have to repay distributions or make additional contributions to us under limited circumstances.

As a limited partner in a partnership organized under Delaware law, you could be held liable for our obligations to the same extent as a general partner if you participate in the control of our business. Our general partner generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions in which we do business. In some of the jurisdictions in which we do business, the applicable statutes do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. You could, however, be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state s partnership statute; or

- your right to act with other Unitholders to take other actions under our partnership agreement is found to constitute control of our business.

Under limited circumstances, our Unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, neither Energy Transfer Equity nor ETP may make a distribution to its Unitholders if the distribution would cause Energy Transfer Equity s or ETP s respective liabilities to exceed the fair value of their respective assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, partners who received the distribution and knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If in the future we cease to manage and control ETP, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control ETP and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the Securities and Exchange Commission or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates.

If Energy Transfer Partners GP withdraws or is removed as ETP s General Partner, then we would lose control over the management and affairs of Energy Transfer Partners, the risk that we would be deemed an investment company under the Investment Company Act of 1940 would be exacerbated and our indirect ownership of the General Partner interests and 100% of the incentive distribution rights in ETP could be cashed out or converted into ETP Common Units at an unattractive valuation.

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Under the terms of ETP s Partnership Agreement, ETP GP will be deemed to have withdrawn as General Partner if, among other things, it:

voluntarily withdraws from the partnership by giving notice to the other partners;

transfers all, but not less than all, of its partnership interests to another entity in accordance with the terms of ETP s Partnership Agreement;

makes a general assignment for the benefit of creditors, files a voluntary bankruptcy petition, seeks to liquidate, acquiesces in the appointment of a trustee, receiver or liquidator, or becomes subject to an involuntary bankruptcy petition; or

dissolves itself under Delaware law without reinstatement within the requisite period.

In addition, ETP GP can be removed as ETP s General Partner if that removal is approved by Unitholders holding at least 66 2/3% of ETP s outstanding units (including units held by ETP GP and its affiliates).

If ETP GP withdraws from being ETP s General Partner in compliance with ETP s partnership agreement or is removed from being ETP s General Partner under circumstances not involving a final adjudication of actual fraud, gross negligence or willful and wanton misconduct, it may require the successor general partner to purchase its general partner interests, incentive distribution rights and limited partner interests in ETP for fair market value. If ETP GP withdraws from being ETP s General Partner in violation of ETP s partnership agreement or is removed from being ETP s General Partner in circumstances where a court enters a judgment that cannot be appealed finding it liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as ETP s General Partner, and the successor general partner does not exercise its option to purchase the general partner interests, incentive distribution rights and limited partner interests held by ETP GP in ETP for fair market value, then the general partner interests and incentive distribution rights held by ETP GP in ETP could be converted into limited partner interests pursuant to a valuation performed by an investment banking firm or other independent expert. Under any of the foregoing scenarios, ETP GP would lose control over the management and affairs of ETP, thereby increasing the risk that we would be deemed an investment company subject to regulation under the Investment Company Act of 1940. In addition, our indirect ownership of the general partner interests and 100% of the incentive distribution rights in ETP, to which a significant portion of the value of our Common Units is currently attributable, could be cashed out or converted into ETP Common Units at an unattractive valuation.

Our Partnership Agreement restricts the rights of Unitholders owning 20% or more of our units.

Our Unitholders voting rights are restricted by the provision in our partnership agreement generally providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our Unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our Unitholders ability to influence the manner or direction of our management. As a result, the price at which our Common Units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Future sales of the ETP Common Units we own or other limited partner interests in the public market could reduce the market price of our Unitholders limited partner interests.

As of December 31, 2008, we owned approximately 62.5 million Common Units of ETP. If we were to sell and/or distribute our ETP Common Units to the holders of our 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 ETP s outstanding Common Units and our receipt of distributions.

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

Prior to making any distributions to our Unitholders, 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 our General Partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to our Unitholders. Our General Partner has sole discretion to determine the amount of these expenses and fees.

In addition, under Delaware partnership law, our General Partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our General Partner, our General Partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash available for distribution to our Unitholders and cause the value of our Common Units to decline.

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

At December 31, 2008, our consolidated balance sheet reflected $773.3 million of goodwill and $215.9 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.

Risks Related to Conflicts of Interest

Although we control ETP through our ownership of its General Partner, ETP s General Partner owes fiduciary duties to ETP and ETP s Unitholders, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, including ETP s General Partner, on the one hand, and ETP and its Limited Partners, on the other hand. The directors and officers of ETP s General Partner have fiduciary duties to manage ETP in a manner beneficial to us, its owner. At the same time, the General Partner has a fiduciary duty to manage ETP in a manner beneficial to ETP and its limited partners. The board of directors of ETP s General Partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our Unitholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to ETP and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and ETP, on the other hand;
- the determination of the amount of cash to be distributed to ETP s partners and the amount of cash to be reserved for the future conduct of ETP s business;
- the determination whether to make borrowings under ETP s revolving working capital facility to pay distributions to ETP s partners; and
- any decision we make in the future to engage in business activities independent of ETP.

The fiduciary duties of our General Partner s officers and directors may conflict with those of ETP s General Partner.

Conflicts of interest may arise because of the relationships between ETP s General Partner, ETP and us. Our General Partner s directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our Unitholders. Some of our General Partner s directors are also directors and officers of ETP s General Partner, and have fiduciary duties to manage the business of ETP in a manner beneficial to ETP and ETP s Unitholders. The resolution of these conflicts may not always be in our best interest or that of our Unitholders.

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Affiliates of our General Partner are not prohibited from competing with us.

Our partnership agreement provides that our General Partner will be restricted from engaging in any business activities other than acting as our General Partner and those activities incidental to its ownership of interests in us. 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. Enterprise GP Holdings L.P. currently has a 40.6% non-controlling equity interest in our General Partner. Enterprise GP Holdings L.P. and its subsidiaries own and operate North American midstream energy business that competes with us with respect to our natural gas midstream business.

Potential conflicts of interest may arise among our General Partner, its affiliates and us. Our General Partner and its affiliates have limited fiduciary duties to us and our Unitholders, which may permit them to favor their own interests to the detriment of us and our Unitholders.

Conflicts of interest may arise among our General Partner and its affiliates, on the one hand, and us and our Unitholders, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over the interests of our Unitholders. These conflicts include, among others, the following:

- Our General Partner is allowed to take into account the interests of parties other than us, including ETP and its affiliates and any general partners and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our Unitholders.

- Our General Partner has limited its liability and reduced its fiduciary duties under the terms of our Partnership Agreement, while also restricting the remedies available to our Unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, Unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.

- Our General Partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to our Unitholders.

- Our General Partner determines which costs it and its affiliates have incurred are reimbursable by us.

- Our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.

- Our General Partner controls the enforcement of obligations owed to us by it and its affiliates.

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

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

Our partnership agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner. 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 good faith if it reasonably believes that the decisions are in our best interests;

generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Audit and Conflicts Committee of the board of directors of our General Partner and not involving a vote of Unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or 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 totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

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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 any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

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

Our General Partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 90% of our outstanding units, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of December 31, 2008, affiliates of our General Partner excluding Enterprise GP Holdings, L.P. own approximately 31.6% of our Common Units.

We own an interstate pipeline that is subject to rate regulation by the Federal Energy Regulatory Commission and, in the event that 15% or more of our outstanding Common Units, in the aggregate, are held by persons who are not eligible holders, Common Units held by persons who are not eligible holders will be subject to the possibility of redemption at the then-current market price.

We own an interstate pipeline that is subject to rate regulation of the Federal Energy Regulatory Commission, or FERC, and as a result our General Partner has the right under our partnership agreement to institute procedures, by giving notice to each of our Unitholders, that would require transferees of Common Units and, upon the request of our General Partner, existing holders of our Common Units to certify that they are Eligible Holders. The purpose of these certification procedures would be to enable us to utilize a federal income tax expense as a component of the pipeline s rate base upon which tariffs may be established under FERC rate-making policies applicable to entities that pass-through their taxable income to their owners. Eligible Holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity s owners are subject to such taxation. If these tax certification procedures are implemented and 15% or more of our outstanding Common Units are held by persons who are not Eligible Holders, we will have the right to redeem the units held by persons who are not Eligible Holders at the then-current market price. The redemption price would be paid in cash or by delivery of a promissory note, as determined by our General Partner.

ETP may issue additional ETP units, which may increase the risk that ETP will not have sufficient Available Cash to maintain or increase its per unit distribution level.

ETP has wide latitude to issue additional units on terms and conditions established by its General Partner. The payment of distributions on those and additional units may increase the risk that ETP may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to distribute to our Unitholders.

The issuance of additional Common Units or other equity securities of equal rank will have the following effects:

- our Unitholders proportionate ownership interest in ETP will decrease;
- the amount of cash available for distribution on each Common Unit may decrease; and
- the market price of our Common Units may decline.

Furthermore, ETP s partnership agreement does not give our Unitholders the right to approve our issuance of equity securities.

Risks Related to Energy Transfer Partners Business

Since our cash flows consist exclusively of distributions from ETP, risks to ETP s business are also risks to us. We have set forth below risks to ETP s business, the occurrence of which could have a negative impact on ETP s financial performance and decrease the amount of cash it is able to distribute to us, thereby impacting the amount of cash that we are able to distribute to our Unitholders.

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ETP may not be able to obtain funding on acceptable terms or at all under its revolving credit facility or otherwise because of the deterioration of the credit and capital markets. This may hinder or prevent ETP from meeting future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including significant write-offs in the financial services sector and the current weak economic conditions. As a result, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt on similar terms or at all and reduced, or in some cases ceased, to provide funding to borrowers. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations. Due to these factors, ETP cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, ETP may be unable to meet its obligations as they come due or ETP may be required to post collateral to support its obligations. Moreover, without adequate funding, ETP may be unable to execute its growth strategy, complete future acquisitions or announced and future pipeline construction projects, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on ETP s revenues and results of operations.

Many of ETP s customers drilling activity levels and spending for transportation on ETP s pipeline system may be impacted by the current deterioration in commodity prices and the credit markets.

Many of ETP s customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of ETP s customers equity values have substantially declined. The combination of a reduction of cash flow resulting from recent declines in natural gas prices, a reduction in borrowing base under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in ETP s customers spending for natural gas drilling activity, which could result in lower volumes being transported on ETP s pipeline systems. For example, a number of ETP s customers have announced reduced drilling capital expenditure budgets for 2009. A significant reduction in drilling activity could have a material adverse effect on ETP s operations.

ETP is exposed to the credit risk of its customers, and an increase in the nonpayment and nonperformance by its customers could reduce its ability to make distributions to its Unitholders, including to us.

The risks of nonpayment and nonperformance by ETP s customers are a major concern in its 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. ETP is subject to risks of loss resulting from nonpayment or nonperformance by its customers. The current tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by ETP s customers. Any substantial increase in the nonpayment and nonperformance by ETP s customers could have a material effect on ETP s results of operations and operating cash flows.

The FERC is pursuing legal action against ETP relating to certain natural gas trading and transportation activities, and related third party actions have been filed against us and ETP.

On July 26, 2007, the FERC issued to ETP an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that ETP violated FERC rules and regulations. The FERC has alleged that ETP 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 occasions from December 2003 through August 2005, in order to benefit financially from ETP s commodities derivatives positions and from certain of its index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods ETP violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the Natural Gas Act (NGA). ETP 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 ETP manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates.

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ETP s Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to the 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. On October 29, 2008, ETP moved for summary disposition of the claim that Oasis unduly discriminated against non-affiliated shippers and unduly preferred affiliated shippers. The presiding administrative law judge granted this motion on November 18, 2008, holding that FERC Staff had failed to make a prima facie case in support of this claim. This ruling, if allowed to stand, significantly narrows the FERC s Oasis-related claims in the Order and Notice proceeding. The FERC also seeks to revoke, for a period of 12 months, ETP s blanket marketing authority for sales of natural gas in interstate commerce at market-based prices, which activity is expected to account for approximately 1.0% of ETP s operating income for our 2008 year. If the FERC is successful in revoking ETP s blanket marketing authority, ETP s sales of natural gas at market-based prices would be limited to sales to retail customers (such as utilities and other end-users) and sales from its own production, and any other sales of natural gas by ETP would be required to be made at contract prices that would be subject to individual FERC approval.

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 has taken the position that, once it receives ETP s 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. On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed the FERC Enforcement Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. 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. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The Enforcement Staff also recommended that FERC issue an order assessing the $15.5 million portion of the above-referenced penalty against ETP with respect to the allegations related to ETP s Oasis pipeline and that the Oasis-related penalty assessment, if not paid, then be referred by the FERC to a federal district court for *de novo* review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis business operations and refunds to certain Oasis customers as previously proposed in the Order and Notice. Finally, the Enforcement Staff recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005, for November 2005 monthly deliveries, a period not previously covered by FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month. If the FERC pursues the claims related to this additional month, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $200.0 million. On March 31, 2008, we responded to the Enforcement Staff s brief. On May 15, 2008, the FERC ordered hearings to be conducted by FERC administrative law judges with respect to the FERC s Oasis claims and market manipulation claims. The hearing related to the Oasis claims was scheduled to commence in December 2008 with the administrative law judge s initial decision due by May 11, 2009, however, as discussed below, ETP entered into a settlement agreement with FERC Enforcement Staff and that agreement was approved by the FERC in its entirety and without modification on February 27, 2009. The hearing related to the market manipulation claims is now scheduled to commence in June 2009 with the administrative law judge s initial decision due by December 3, 2009. The FERC also ordered that, following the completion of the hearings, the administrative law judges make initial findings with respect to whether we engaged in market manipulation in violation of the NGA and FERC regulations and whether Oasis violated the NGPA and FERC regulations. The FERC reserved for itself the issues of possible civil penalties, revocation of our blanket market certificate, the method by which we and Oasis would disgorge any unjust profits and whether any conditions should be placed on Oasis s Section 311 authorization. Following the issuance of each of the administrative law judge s initial decisions, the FERC would then issue an order with respect to each of these matters. On May 23, 2008, we requested rehearing and stay of the FERC s May 15, 2008 order establishing hearing, and we renewed those requests on June 26, 2008. On August 7, 2008, FERC denied rehearing of its May 15, 2008 order. On August 8, 2008, we filed a petition with the U.S. Court of Appeals for the Fifth Circuit to review and set aside FERC s May 15 and August 7, 2008 orders on the grounds that we are entitled to adjudicate FERC s claims in federal district court pursuant to the NGA and the NGPA. On August 28, 2008, we filed an amended petition seeking review of the Order and Notice and the December 20, 2007 order denying rehearing.

On November 18, 2008, the administrative law judge presiding over the Oasis claims granted ETP s motion for summary disposition of the claim that Oasis unduly discriminated in favor of affiliates regarding the provision of Section 311(a)(2) interstate transportation service. ETP subsequently entered into an agreement with the Enforcement Staff to settle all of the claims related to Oasis. On January 5, 2009, this agreement was submitted under seal to FERC by the presiding administrative law judge, for FERC s approval as

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an uncontested settlement of all Oasis claims. On February 27, 2009, the settlement agreement was approved by the FERC in its entirety and without modification and the terms of the settlement were made public. If no person seeks rehearing of the order approving the settlement within 30 days of such order, the FERC s order will become final and non-appealable. We do not believe the Oasis settlement, as approved by the FERC, will have a material adverse effect on our business, financial condition or results of operations.

It is ETP s position that its trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and ETP intends 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 holds substantial enforcement authority. At this time, neither we nor ETP is able to predict the final outcome of these matters.

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 (the CEA) by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, ETP entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, ETP agreed to pay the CFTC $10.0 million and the CFTC agreed to release ETP and its affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that ETP is permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the CEA. By consenting to the entry of the Consent Order, ETP neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations in March 2008.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETP for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETP for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETP contains an additional allegation that we and ETP transported gas in a manner that favored our and ETP s affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have moved to compel arbitration and/or contested subject-matter jurisdiction in some of these cases. One such case currently is on appeal before the Texas Supreme Court on, among other things, the issue of whether the dispute is arbitrable.

We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producers/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The claimants have filed a notice of appeal.

A consolidated class action complaint has been filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the New York Mercantile Exchange, or NYMEX, in violation of the CEA. It is further alleged that during the class period December 29, 2003 to December 31, 2005, ETP had the market power to manipulate index prices, and that it used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit its natural gas physical and financial trading positions and that ETP intentionally submitted price and volume trade information to trade publications. This complaint also alleges that ETP violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by ETP manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action, and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, ETP filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, ETP filed a motion to dismiss the complaint. On June 19, 2008 the plaintiffs filed a response opposing ETP s motion to dismiss. ETP filed a reply in support of its motion on July 9, 2008.

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On March 17, 2008, a second class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period ETP exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit from its own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, ETP filed a motion to dismiss this complaint. On July 2, 2008 the plaintiffs filed a response opposing ETP s motion to dismiss. ETP filed a reply in support of our motion on August 18, 2008.

We are expensing the legal fees, consultants fees and other 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 to service our indebtedness 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 and our liquidity.

The profitability of ETP s midstream and intrastate transportation and storage operations are, 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 ETP s control and have been volatile.

Income from ETP s midstream and intrastate transportation and storage operations is 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 ETP s HPL System, ETP purchases natural gas from producers at the wellhead and then gathers and delivers the natural gas to pipelines where ETP typically resells the natural gas under various arrangements, including sales at index prices. Generally, the gross margins ETP realizes under these arrangements decrease in periods of low natural gas prices.

For a portion of the natural gas gathered and processed at the North Texas System and Southeast Texas System, ETP enters into percentage-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which ETP agrees to gather and process natural gas received from the producers. Under percentage-of-proceeds arrangements, ETP generally sells the residue gas and NGLs at market prices and remits 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, ETP delivers an agreed upon percentage of the residue gas and NGL volumes to the producer and sells the volumes it keeps to third parties at market prices. Under these arrangements, ETP s 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 ETP s results of operations. Under keep-whole arrangements, ETP generally sells the NGLs produced from its 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, ETP 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, ETP s revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs if ETP is not able to bypass its 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 ETP expects this volatility to continue. For example, during ETP s year ended December 31, 2008, the NYMEX settlement price for the prompt month contract ranged from a high of $13.11 per MMBtu to a low of $6.47 per MMBtu. A composite of the Mt. Belvieu average NGLs price based upon ETP s average NGLs composition during ETP s year ended December 31, 2008 ranged from a high of approximately $1.96 per gallon to a low of approximately $0.66 per gallon.

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ETP s Oasis pipeline, East Texas pipeline, ET Fuel System and HPL System receive fees for transporting natural gas for its 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 ETP s 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. ETP s fuel retention fees are also directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase ETP s fuel retention fees, and decreases in natural gas prices tend to decrease its fuel retention fees.

The markets and prices for natural gas and NGLs depend upon factors beyond ETP s 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 ETP.

From time to time, ETP has 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 risk management mechanisms. To the extent that ETP hedges its commodity price and interest rate exposures, it foregoes the benefits it would otherwise experience if commodity prices or interest rates were to change in ETP s favor. In addition, even though monitored by management, ETP s derivatives 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 ETP s physical or financial positions, or hedging policies and procedures are not followed.

ETP s success depends upon its ability to continually contract for new sources of natural gas supply.

In order to maintain or increase throughput levels on ETP s gathering and transportation pipeline systems and asset utilization rates at its treating and processing plants, ETP must continually contract for new natural gas supplies and natural gas transportation services. ETP may not be able to obtain additional contracts for natural gas supplies for its natural gas gathering systems, and it may be unable to maintain or increase the levels of natural gas throughput on its transportation pipelines. The primary factors affecting ETP s ability to connect new supplies of natural gas to its gathering systems include its 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 ETP s gathering systems or in areas that provide access to its transportation pipelines or markets to which its systems connect. The primary factors affecting ETP s ability to attract customers to its transportation pipelines consist of its 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. ETP has no control over the level of drilling activity in its 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, ETP has 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. Natural gas prices have been high in recent years compared to historical periods, but have decreased significantly during the fourth quarter of 2008 and thus far in 2009. This decline in natural gas prices coupled with the effect of illiquid capital markets has led to a decrease in drilling activity in some of our areas of operation.

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

ETP s transportation pipelines are also dependent upon natural gas production in areas served by its pipelines or in areas served by other gathering systems or transportation pipelines that connect with its transportation pipelines. A material decrease in natural gas production in ETP s areas of operation or in other areas that are connected to ETP s 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 ETP handles, which would reduce ETP s revenues and operating income. In addition, ETP s future growth will depend, in part, upon whether it can contract for additional supplies at a greater rate than the natural decline rate in ETP s currently connected supplies.

Transwestern derives a significant portion of its revenue from charging its customers for reservation of capacity, which 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 ETP transports on its 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 ETP s 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 ETP operates.

ETP may not be able to fully execute its growth strategy if it encounters increased competition for qualified assets.

ETP s 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 its ability to compete effectively and diversify its asset portfolio, thereby providing more stable cash flow. ETP regularly considers and enters into discussions regarding, and are currently contemplating, the acquisition of additional assets and businesses, stand alone development projects or other transactions that ETP believes will present opportunities to realize synergies and increase its cash flow.

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

In addition, ETP is experiencing increased competition for the assets it purchases or contemplates purchasing. Increased competition for a limited pool of assets could result in ETP losing to other bidders more often or acquiring assets at higher prices, both of which would limit ETP s ability to fully execute its growth strategy. Inability to execute its growth strategy may materially adversely impact ETP s results of operations.

If ETP does not make acquisitions on economically acceptable terms, its future growth could be limited.

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

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

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

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

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease its liquidity by using a significant portion of its available cash or borrowing capacity to finance acquisitions;
- significantly increase its interest expense or financial leverage if ETP incurs 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 ETP is not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate its growing business and assets;
- less effectively manage its historical assets, due to the diversion of ETP 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.

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

If ETP does not continue to construct new pipelines, its future growth could be limited.

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

- ETP is unable to identify pipeline construction opportunities with favorable projected financial returns;
- ETP is unable to raise financing for its identified pipeline construction opportunities; or
- ETP is 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 ETP constructs a pipeline that it believes will be accretive, the pipeline may in fact adversely affect its results of operations or results from those projected prior to commencement of construction and other factors.

Expanding ETP s business by constructing new pipelines and treating and processing facilities subjects it to risks.

One of the ways that ETP has grown its business is through the construction of additions to its 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

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or treating facilities, involve numerous regulatory, environmental, political and legal uncertainties beyond ETP s control and require the expenditure of significant amounts of capital that ETP will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If ETP undertakes these projects, they may not be completed on schedule or at all or at the budgeted cost. ETP currently has several major expansion and new build projects planned or underway, including the Texas Independence pipeline, the Midcontinent Express pipeline, the Fayetteville Express pipeline and the Tiger pipeline. A variety of factors outside ETP s control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors has resulted in, and may continue to result in, increased costs or delays in construction. Cost overruns or delays in completing a project could have a material adverse effect on ETP s results of operations and cash flows. Moreover, ETP s revenues may not increase immediately following the completion of particular projects. For instance, if ETP builds a new pipeline, the construction will occur over an extended period of time, but ETP may not materially increase its revenues until long after the project s completion. In addition, 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 ETP s ability to obtain commitments from producers in this area to utilize the newly constructed pipelines. In this regard, ETP may construct facilities to capture anticipated future growth in natural gas 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 ETP s expected investment return, which could adversely affect its results of operations and financial condition.

ETP depends on certain key producers for its 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 its financial results.

For ETP s year ended December 31, 2008, XTO Energy Inc., EnCana Oil and Gas (USA), Inc., Sandridge Energy Inc., and ConocoPhillips Company supplied ETP with approximately 75% of the Southeast Texas System s natural gas supply. For ETP s year ended December 31, 2008, XTO Energy Inc., Chesapeake Energy Marketing, Inc., EnCana Oil and Gas (USA), Inc. and EOG Resources, Inc. supplied ETP with approximately 75% of the North Texas System s natural gas supply. ETP is 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 ETP, ETP would be adversely affected unless it was able to acquire comparable supplies of natural gas from other producers.

ETP depends on key customers to transport natural gas through its pipelines.

ETP has nine- and ten-year fee-based transportation contracts with XTO Energy, Inc. (XTO) that terminate in 2013 and 2017, respectively, pursuant to which XTO has committed to transport certain minimum volumes of natural gas on pipelines in ETP s ET Fuel System. ETP also has an eight-year fee-based transportation contract with TXU Portfolio Management Company, L.P., a subsidiary of TXU Corp., which is referred to as TXU Shipper, to transport natural gas on the ET Fuel System to TXU s electric generating power plants. ETP has also entered into two eight-year natural gas storage contracts that terminate in 2012 with TXU Shipper to store natural gas at the two 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 or TXU Shipper to fulfill their contractual obligations under these contracts could have a material adverse effect on ETP s cash flow and results of operations if ETP was not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

The major shippers on our intrastate transportation pipelines include XTO, EOG Resources, Inc., Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. and Quicksilver Resources, Inc. These shippers have long-term contracts that have remaining terms ranging from three to eight years. The failure of these shippers to fulfill their contractual obligations could have a material adverse effect on ETP s cash flow and results of operations if ETP was not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

With respect to ETP s interstate transportation operations, MEP has secured predominantly 10-year firm transportation contracts from a small number of major shippers for all of the initial 1.5 Bcf/d of capacity on the Midcontinent Express pipeline. MEP has also secured firm transportation commitments for an additional 0.3 Bcf/d of capacity on the Midcontinent Express pipeline, which expansion is subject to regulatory approval. FEP has secured a binding 10-year commitment for approximately 1.85 Bcf/d of firm transportation service on the 2.0 Bcf/d Fayetteville Express pipeline project. In connection with ETP s Tiger pipeline project, ETP has entered into an agreement with Chesapeake Energy Marketing, Inc. that provides for a 15-year commitment for firm transportation capacity of approximately 1.0 Bcf/d of the total initial capacity of at least 1.25 Bcf/d. The failure of these key shippers to fulfill their contractual obligations could have a material adverse effect on ETP s and our cash flow and results of operations if ETP 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 the business and operations of ETP s midstream and intrastate assets.

ETP s midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects its business and the market for its products. The rates, terms and conditions of some of the transportation and storage services ETP provides 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 its currently approved rates ETP 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.

ETP s intrastate transportation and storage operations are subject to state regulation in Texas, New Mexico, Arizona, Louisiana, Utah and Colorado, the states in which ETP operates these types of natural gas facilities. ETP s intrastate transportation operations 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 ETP charges 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, ETP s business may be adversely affected.

ETP s midstream 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 ETP s rights as an owner of gathering facilities to decide with whom it contracts 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 ETP operates have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which ETP operates 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 ETP s business.

ETP s 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.

The states in which ETP conducts 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 ETP s 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.

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Failure to comply with applicable laws and regulations could result in the imposition of administrative, civil and criminal remedies.

ETP s interstate pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of ETP s interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs. NGA-jurisdictional natural gas companies must charge rates that are just and reasonable by FERC. The rates charged by natural gas companies are generally required to be on file with FERC in FERC-approved tariffs. Pursuant to the NGA, existing tariff rates may be challenged by complaint and rate increases proposed by the natural gas company may be challenged by protest. ETP also may be limited by the terms of negotiated rate agreements from seeking future rate increases, or constrained by competitive factors from charging its FERC-approved maximum just and reasonable rates. Further, rates must, for the most part, be cost-based and FERC may, on a prospective basis, order refunds of amounts collected under rates that have been found by FERC to be 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 a new general rate case until October 2011. However, shippers (other than shippers that have agreed, as parties to the Stipulation and Agreement, not to challenge Transwestern s tariff rates through the remaining term of the settlement) may challenge the lawfulness of tariff rates that have become final and effective. FERC may also investigate such rates absent shipper complaint.

Most of the rates to be paid by the initial shippers on the Midcontinent Express pipeline are established pursuant to long-term, negotiated rate transportation agreements. Other prospective shippers on Midcontinent Express pipeline that elect not to pay a negotiated rate for service may opt instead to pay a cost-based recourse rate established by FERC as part of Midcontinent Express pipeline s certificate of public convenience and necessity. Negotiated rate agreements generally provide a degree of certainty to the pipeline and shipper as to a fixed rate during the term of the relevant transportation agreement, but such agreements can limit the pipeline s future ability to collect costs associated with construction and operation of the pipeline that might be higher than anticipated at the time the negotiated rate agreement was entered. The certificate order authorizing construction, ownership and operation of Midcontinent Express pipeline is subject to pending requests for clarification and rehearing, and ETP cannot guarantee that this order will not be altered on rehearing or that judicial review, if any, will not result in any change to FERC s Midcontinent Express pipeline certificate order on remand.

Any successful complaint or protest against the rates of ETP s interstate natural gas companies could reduce its revenues associated with providing transportation services on a prospective basis. We and ETP cannot assure you that ETP s interstate pipelines will be able to recover all of their costs through existing or future rates.

The ability of interstate pipelines held in tax-pass-through entities, like ETP, 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 ETP, 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. It is currently FERC s policy to 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 FERC on a case-by-case basis. Under the FERC s policy, ETP thus remains eligible to include an income tax allowance in the tariff rates its charges for interstate natural gas transportation. The application of that policy remains subject to future refinement or change by FERC. With regard to rates charged and collected by Transwestern, the allowance for income taxes as a cost-of-service element in ETP s tariff rates is generally not subject to challenge prior to the expiration of its settlement agreement in 2011.

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The interstate pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect their business and operations.

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

- operating terms and conditions of service;
- the types of services interstate pipelines may offer their 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 the ability of ETP s interstate pipelines to compete for business, may impair their ability to recover costs, or may increase the cost and burden of operation.

ETP must on occasion rely upon rulings by FERC or other governmental authorities to carry out certain of its business plans. For example, in order to carry out its plan to construct the Fayetteville Express pipeline ETP must, among other things, file and support before FERC an NGA Section 7(c) application for a certificate of public convenience and necessity to build, own and operate such a facility. We and ETP cannot guarantee that FERC will authorize construction and operation of this facility. Moreover, there is no guarantee that, if granted, such certificate authority will be granted in a timely manner or will be free from potentially burdensome conditions. Similarly, ETP was required to obtain from FERC a certificate of public convenience and necessity to build, own and operate the Midcontinent Express pipeline. Although FERC has granted ETP such certificate authority, there are pending requests for clarification and rehearing of that order. We and ETP cannot guarantee that FERC will, on rehearing, reaffirm in all materials respects its July 25, 2008 Midcontinent Express certificate order. Nor can we or ETP guarantee that FERC s certificate order will not be subject to judicial review and, ultimately, to possible material alteration if remanded to FERC.

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 NGA to impose penalties for current violations of up to $1.0 million per day for each violation. FERC possesses similar authority under the NGPA.

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

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

ETP s natural gas as well as its 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 ETP s pipelines, plants, and facilities, and impose substantial liabilities for pollution resulting from ETP s 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.

ETP may incur substantial environmental costs and liabilities because of the underlying risk inherent to its operations. Environmental laws provide for joint and several strict liability for cleanup costs incurred to address discharges or releases of petroleum hydrocarbons or wastes on, under, or from ETP s properties and facilities, many of which have been used for industrial activities for a number of years, even if such discharges were caused by its predecessors. Private parties, including the owners of properties through which ETP s gathering systems pass or facilities where its 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 ETP s Transwestern pipeline operations is approximately $9.1 million, which activities are expected to continue through 2018.

Changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. For example, the EPA in 2008 lowered the federal ozone standard from 0.08 parts per million to 0.075 parts per million, which will require the environmental agencies in states with areas that do not currently meet this standard to adopt new rules between to further reduce NOx and other ozone precursor emissions. We have previously been able to satisfy the more stringent NOx emission reduction requirements that affect our compressor units in ozone non-attainment areas at reasonable cost, but there is no guarantee that the changes we may have to make in the future to meet the new ozone standard or other evolving standards will not require us to incur costs that could be material to our operations.

In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth s atmosphere, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider, legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. These cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire emission allowances from other businesses that emit greenhouse gases at levels lower than the limits specified in those programs and then surrender these allowances as a credit against such emissions. Depending on the particular program, ETP could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from ETP s operations (*e.g.*, compressor stations) or from the combustion of fuels (*e.g.*, natural gas) that ETP processes.

Also, as a result of the United States Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court s decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could also have an adverse affect on our cost of doing business and demand for the natural gas ETP processes and transports.

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

Users of ETP s 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 ETP s 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 ETP s pipelines. Any reduction in volumes transported in ETP s pipelines would adversely affect its revenues and cash flow.

ETP encounters competition from other midstream, transportation and storage companies and propane companies.

ETP experiences competition in all of its markets. ETP s 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 its transportation pipeline systems. ETP s 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.

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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 ETP competes with in these areas include those owned by Atmos Energy Corporation, Enterprise Products Partners, L.P., and Enbridge, Inc. Some of ETP s competitors may have greater financial resources and access to larger natural gas supplies than it does.

The acquisitions of the HPL System and the Transwestern pipeline increased the number of interstate pipelines and natural gas markets to which ETP has access and expanded its principal areas of competition to areas such as southeast Texas and the Texas Gulf Coast. As a result of ETP s expanded market presence and diversification, ETP faces 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 ETP does.

The Transwestern pipeline competes with, and upon completion, the Midcontinent Express pipeline and the Fayetteville Express pipeline will compete with, 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.

ETP s 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 ETP s retail outlets. As a result, ETP is always subject to the risk of additional competition in the future. Generally, warmer-than-normal weather further intensifies competition. Most of ETP s retail propane 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.

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

Because of ETP s ownership of the Oasis pipeline and ET Fuel System, it can generally elect to bypass ETP s processing plants 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 ETP does not have a sufficient amount of lean gas to blend with the volume of rich gas that it receives at the processing plant, ETP may have to process the rich gas. If ETP has to process when processing margins are unfavorable, its results of operations will be adversely affected.

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

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

For ETP s year ended December 31, 2008, approximately 27.3% of its 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 ETP in the marketing of natural gas, ETP often competes in the end-user and utilities markets primarily on the basis of price. The inability of ETP s management to renew or replace its current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on ETP s profitability.

ETP s storage business depends on neighboring pipelines to transport natural gas.

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

ETP s pipeline integrity program may cause it to incur significant costs and liabilities.

ETP s 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. Based on the results of ETP s current pipeline integrity testing programs, ETP estimates 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 $27.1 million over the course of the next year, as well as operating and maintenance costs of $27.6 million during that period. During this same time period, ETP estimates that it will incur pipeline integrity costs of $8.9 million, as well as operating and maintenance cost of $1.7 million, with respect to its Transwestern pipeline. Through December 31, 2008, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2009. Through December 31, 2008, a total of $16.4 million of capital costs and $12.7 million of operating and maintenance costs have been incurred for pipeline integrity testing for transportation assets other than Transwestern. Through December 31, 2008, a total of $6.9 million of capital costs and $0.4 million of operating and maintenance costs have been incurred for pipeline integrity costs 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 ETP 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.

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Since weather conditions may adversely affect demand for propane, ETP s 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 ETP s customers rely heavily on propane as a heating fuel. Typically, ETP sells approximately two-thirds of its retail propane volume during the peak-heating season of October through March. ETP s 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 ETP s operating and financial results, its access to capital and its acquisition activities may be limited. Variations in weather in one or more of the regions where ETP operates can significantly affect the total volume of propane that ETP sells and the profits realized on these sales. Agricultural demand for propane may also be affected by weather, including unseasonably cold or hot periods or dry weather conditions that impact agricultural operations.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail ETP s operations and otherwise materially adversely affect its cash flow.

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

If one or more facilities that are owned by ETP or that deliver natural gas or other products to ETP are damaged by severe weather or any other disaster, accident, catastrophe or event, ETP s operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply ETP s facilities or other stoppages arising from factors beyond its 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 ETP s operations, or which causes it to make significant expenditures not covered by insurance, could reduce ETP s cash available for paying distributions to its Unitholders, including us.

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, ETP may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If ETP were to incur a significant liability for which it was not fully insured, it could have a material adverse effect on ETP s 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.

Terrorist attacks aimed at ETP s facilities could adversely affect its 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 the nation s pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on ETP s facilities or pipelines or those of its customers could have a material adverse effect on ETP s business.

Sudden and sharp propane price increases that cannot be passed on to customers may adversely affect ETP s 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, ETP s 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, ETP may be unable to pass on these increases to its customers through retail or wholesale prices. Propane is a commodity and the price ETP pays for it can fluctuate significantly in response to changes in supply or other market conditions over which ETP has no control. In addition, the timing of cost pass-throughs can significantly affect margins. Sudden and extended wholesale price increases could reduce ETP s gross profits and could, if continued over an extended period of time, reduce demand by encouraging ETP s retail customers to conserve their propane usage or convert to alternative energy sources.

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ETP s results of operations could be negatively impacted by price and inventory risk related to its propane business and management of these risks.

ETP generally attempts to minimize its cost and inventory risk related to its 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, ETP may purchase large volumes of propane during periods of low demand or low price, which generally occur during the summer months, for storage in its facilities, at major storage facilities owned by third parties or for future delivery. This strategy may not be effective in limiting ETP s 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 ETP made such purchases, it could adversely affect its profits.

Some of ETP s propane sales are pursuant to commitments at fixed prices. To mitigate the price risk related to ETP s anticipated sales volumes under the commitments, ETP 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. ETP enters into such contracts and exercises such options at volume levels that it believes are necessary to manage these commitments. The risk management of ETP s inventory and contracts for the future purchase of product could impair its profitability if the customers do not fulfill their obligations.

ETP also engages 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 ETP 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 ETP s control occur, such activities could generate a loss in future periods and potentially impair its profitability.

ETP is dependent on its principal propane suppliers, which increases the risk of an interruption in supply.

During 2008, ETP purchased approximately 50.7%, 15.0% and 14.9% of its propane from Enterprise, Targa Liquids and M.P. Oils, Ltd., respectively. Enterprise is a subsidiary of Enterprise GP, an entity that owns approximately 17.6% of ETE s outstanding Common Units and a 40.6% non-controlling equity interest in our General Partner. 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 ETP purchases originated from one of the industry s major markets located in Mt. Belvieu, Texas and has been shipped to ETP 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 ETP uses, would adversely affect its ability to obtain propane.

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

Competition in ETP s 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 ETP to lose customers, thereby reducing its 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 ETP s operations.

Energy efficiency and technological advances may affect the demand for propane and adversely affect ETP s 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 ETP s operations.

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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 or ETP 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 matter. The value of our investment in ETP depends largely on ETP being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. If we are so treated, 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.

If ETP were treated as a corporation for federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate. Distributions to us would generally be taxed again as corporate distributions, and no income, gains, losses, deduction or credits would flow through to us. As a result, there would be a material reduction in our anticipated cash flow, likely causing a substantial reduction in the value of our units. Current law may change, causing us or ETP to be treated as a corporation for federal income tax purposes or otherwise subjecting us or ETP to entity-level taxation. For example, members of Congress have recently considered substantive changes to the existing federal income tax laws that would have affected certain publicly traded partnerships. Specifically, federal income tax legislation has been considered that would have eliminated partnership tax treatment for certain publicly traded partnerships and recharacterize certain types of income received from partnerships. We or ETP are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our or ETP s common units.

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 or ETP takes, the market for our Common Units or ETP 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 positions we or ETP take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we or ETP take. A court may not agree with some or all of the positions we or ETP take. Any contest with the IRS may materially and adversely impact the market for our Common Units or ETP s Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us or ETP, and therefore indirectly by us, as a Unitholder and as the owner of the general partner of ETP, 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 Unitholders may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. 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 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.

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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.

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.

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

When we or ETP issue additional units or engage in certain other transactions, ETP determines the fair market value of its assets and allocates any unrealized gain or loss attributable to such assets to the capital accounts of ETP s Unitholders and us. Although ETP may from time to time consult with professional appraisers regarding valuation matters, including the valuation of its assets, ETP makes many of the fair market value estimates of its assets itself using a methodology based on the market value of its Common Units as a means to measure the fair market value of its assets. ETP s methodology may be viewed as understating the value of ETP s assets. In that case, there may be a shift of income, gain, loss and deduction between certain ETP Unitholders and us, which may be unfavorable to such ETP 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 ETP s tangible assets and a lesser portion allocated to ETP s intangible assets. The IRS may challenge ETP s valuation methods, or our or ETP s allocation of Section 743(b) adjustment attributable to ETP s tangible and intangible assets, and allocations of income, gain, loss and deduction between us and certain of ETP s 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 or the ETP Unitholders. It also could affect the amount of gain on the sale of Common Units by our Unitholders or ETP s Unitholders and could have a negative impact on the value of our Common Units or those of ETP or result in audit adjustments to the tax returns of our or ETP s Unitholders without the benefit of additional deductions.

A Unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of those units. If so, the Unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a Unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the Unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

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

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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.

The sale of our Common Units by Ray C. Davis and Natural Gas Partners VI, L.P. to Enterprise GP Holdings, L.P. on May 7, 2007, together with all other Common Units sold within the prior twelve months, represented a sale or exchange of 50% or more of the total interest in our capital and profits interests and resulted in our termination and immediate reconstitution as a new partnership for federal income tax purposes. Moreover, our termination resulted in a deemed transfer of all of our interests in ETP, causing a termination of ETP s partnership for federal income tax purposes. These terminations did not affect our classification or the classification of ETP as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income or the qualifying income of ETP for federal income tax purposes. The closing of our taxable years resulted in us and ETP both filing two tax returns (and Unitholders receiving two Schedule K-1 s) for one fiscal year. Moreover, these terminations requireed both us and ETP to close our taxable years and make new elections as to various tax matters. In addition, ETP was required to reset the depreciation schedule for its depreciable assets for federal income tax purposes. The resetting of ETP s depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to the Unitholders of ETP (including Heritage Holdings as the holder of our Class E units) and, consequently, to our Unitholders. However, elections ETP and ETE made with respect to the amortization of certain intangible assets had the effect of reducing the amount of taxable income that would otherwise be allocated to ETE Unitholders.

The net effect of our tax termination and the tax termination of ETP was an allocation for the 2007 year of (i) an increased amount of taxable income as a percentage of the cash distributed to our Unitholders who acquired their units prior to our initial public offering in February 2006 and (ii) a decrease in the amount of taxable income as a percentage of the cash distributed to our Unitholders who purchased their units on or after the date of our initial public offering in February 2006.

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 or ETP 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.

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 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. We also own and operate three natural gas storage facilities, including the Bammel facility, and own or lease other natural gas treating and conditioning facilities in connection with our midstream operations.

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 49.3 million gallons of aboveground storage capacity at our various propane plant sites and have leased an aggregate of approximately 19.2 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).

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 an 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 own a field office building in Fruita, Colorado and lease office facilities in Houston, Texas, San Antonio, Texas, Florence, Kentucky, Tulsa, Oklahoma, Wexford, Pennsylvania, Bridgeport, West Virginia 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.

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 December 31, 2008, we utilized approximately 228 transport truck tractors, 274 transport trailers, 19 railroad tank cars, 2,075 bobtails and 3,866 other delivery and service vehicles, all of which we own. As of December 31, 2008, we owned approximately 1,200,000 customer storage tanks with typical capacities of 120 to 1,000 gallons that are leased or available for lease to customers. These customer storage tanks are pledged as collateral to secure the obligations of HOLP to its banks and the holders of its notes.

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

ITEM 3. LEGAL PROCEEDINGS

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

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For a description of legal proceedings, see note 11 to our consolidated financial statements.

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

None. See Note 7 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

Parent Company

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

The Parent Company s Common Units are listed on the New York Stock Exchange under the symbol ETE . 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 Transaction Tape, and the amount of cash distributions paid per Common Unit since the Parent Company s initial public offering (IPO) in February 2006.

	Price Range		Cash
	High	Low	Distribution (1)
Fiscal Year 2008			
Fourth Quarter Ended December 31, 2008	$ 22.35	$ 12.75	$ 0.5100
Third Quarter Ended September 30, 2008	$ 30.31	$ 19.00	$ 0.4800
Second Quarter Ended June 30, 2008	$ 35.02	$ 28.47	$ 0.4800
First Quarter Ended March 31, 2008	$ 35.26	$ 26.99	$ 0.4400
Transition Period 2007			
Four Months Ended December 31, 2007 (2)	$ 37.35	$ 31.55	$ 0.5500
Fiscal Year 2007			
Fourth Quarter Ended August 31, 2007	$ 42.95	$ 29.82	$ 0.3900
Third Quarter Ended May 31, 2007	$ 41.06	$ 33.20	$ 0.3725
Second Quarter Ended February 28, 2007	$ 33.70	$ 28.80	$ 0.3560
First Quarter Ended November 30, 2006	$ 29.99	$ 26.04	$ 0.3400

(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.

(2) We changed our fiscal year to the calendar year in November 2007. In connection with this change, we have transitioned to making quarterly cash distributions on a calendar quarter basis that are paid within 50 days following the end of each calendar quarter. To facilitate this transition, we did not make a cash distribution for the three-month period ending November 30, 2007, but instead made a cash distribution for the four-month period ending December 31, 2007 that was paid on February 19, 2008.

Description of Units

As of January 31, 2009, there were approximately 21,540 individual Common Unitholders, which includes Common Units held in street name. Common Units represent limited partner interest in the Partnership s Amended and Restated Agreement of Limited Partnership, as amended to date (the Partnership Agreement) that entitle the holders to the rights and privileges specified in the Partnership Agreement.

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Common Units. As of December 31, 2008, we had 222,829,956 Common Units outstanding, of which 113,356,021 were held by the public; 39,768,401 were held by affiliates and 69,705,534 were held by our officers and directors. As of such date, the Common Units represent an aggregate 99.69% limited partner interest in us. Our General Partner owns an aggregate 0.31% General Partner interest in us. Our Common Units are registered under the Securities Exchange Act of 1934, as amended and are listed for trading on the New York Stock Exchange (the NYSE). Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

Cash Distribution Policy

General. The Parent Company will distribute all of its Available Cash to its Unitholders and its General Partner within 50 days following the end of each fiscal quarter.

Definition of Available Cash. Available Cash is defined in the Parent Company s 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 its business;
- comply with applicable law or any debt instrument or other agreement; and
- provide funds for distributions to Unitholders and its General Partner in respect of any one or more of the next four quarters.

The total amount of distributions declared are reflected in Note 7 to our consolidated financial statements.

Securities Authorized for Issuance Under Equity Incentive Plans

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

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

Currently, the Parent Company has no separate operating activities apart from those conducted by the Operating Partnerships. The table below reflects the consolidated operations of the Parent Company including the operations of ETP and its consolidated subsidiaries, except as indicated below.

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. (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 a December 31 year-end. ETC OLP s predecessor entities had a December 31 year-end.

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In November 2007, we changed our fiscal year end from August 31 to December 31 and, in connection with such change, we have reported financial results for a four-month transition period ended December 31, 2007.

The selected historical financial data should be read in conjunction with the consolidated financial statements of Energy Transfer Equity, 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.

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006	2005	2004
Statement of Operations Data:						
Revenues:						
Midstream segment	$ 5,342,393	$ 1,166,313	$ 2,853,496	$ 4,223,544	$ 3,246,772	$ 1,880,663
Intrastate transportation and storage segment	5,634,604	1,254,401	3,915,932	5,013,224	2,608,108	113,938
Interstate transportation segment	244,224	76,000	178,663			
Eliminations	(3,568,065)	(664,522)	(1,562,199)	(2,359,256)	(471,255)	(27,798)
Retail propane and other retail propane related segment	1,624,010	511,258	1,284,867	879,556	709,473	349,344
Other	16,201	5,892	121,278	102,028	75,700	30,810
Total revenues	9,293,367	2,349,342	6,792,037	7,859,096	6,168,798	2,346,957
Gross margin	2,355,287	675,688	1,713,831	1,290,780	787,283	365,533
Depreciation and amortization	274,372	75,406	191,383	129,636	105,751	56,242
Operating income	1,098,903	316,651	809,336	575,540	297,921	130,806
Interest expense, net of interest capitalized	(357,541)	103,375	279,986	150,646	101,061	41,217
Gain on Energy Transfer Transactions						395,253
Income from continuing operations before income tax expense and minority interest	683,562	192,758	563,359	433,907	201,795	484,715
Income tax expense (a)	3,808	9,949	11,391	23,015	4,397	2,792
Minority interests in income from continuing operations	(304,710)	(90,132)	(232,608)	(303,752)	(96,946)	(35,164)
Income from continuing operations	375,044	92,677	319,360	107,140	100,452	446,759
Basic income from continuing operations per limited partner unit (b)	1.68	0.41	1.56	0.80	0.89	4.54
Diluted income from continuing operations per limited partner unit (b)	1.68	0.41	1.55	0.79	0.75	3.35
Cash distribution per unit	1.91	0.55	1.46	2.56	2.66	1.36
Balance Sheet Data (at period end):						
Current assets	1,180,995	1,403,796	1,050,578	1,302,736	1,453,730	481,868
Total assets	11,069,902	9,462,094	8,183,089	5,924,141	4,905,672	2,865,191
Current liabilities	1,208,921	1,241,433	932,815	1,020,787	1,244,785	404,917
Long-term debt, less current maturities	7,190,357	5,870,106	5,198,676	3,205,646	2,275,965	1,071,158
Partners capital (deficit)/Stockholders' equity	(83,432)	(15,663)	(47,132)	45,751	(88,137)	368,325
Other Financial Data:						
Cash flow provided by operating activities	823,757	147,118	754,497	310,782	38,133	122,098
Cash flow used in investing activities	(2,015,585)	(995,943)	(2,158,090)	(1,244,406)	(1,131,117)	(731,831)
Cash flow provided by financing activities	1,227,294	828,032	1,454,739	926,369	1,043,591	637,513
Capital expenditures:						
Maintenance (accrual basis)	140,968	48,998	89,226	51,826	41,054	22,514
Growth (accrual basis)	1,921,679	604,371	998,075	677,861	155,405	87,174
Acquisition	84,783	337,092	90,695	586,185	1,131,844	622,929

(a) As a partnership, we are generally 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.

(b) See Note 4 to our consolidated financial statements for a discussion of the computation of income per limited partner unit.

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

Energy Transfer Equity, L.P. is a Delaware limited partnership, whose Common Units are publicly traded on the New York Stock Exchange (NYSE) under the ticker symbol ETE . ETE was formed in September 2002 and completed its IPO of 24,150,000 Common Units in February 2006.

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. This discussion 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.

Unless the context requires otherwise, references to we, us, our, and ETE shall mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (ETP), Energy Transfer Partners G.P., L.P. (ETP GP), the General Partner of ETP, and ETP GP s General Partner, Energy Transfer Partners, L.L.C. (ETP LLC). References to the Parent Company shall mean Energy Transfer Equity, L.P. on a stand-alone basis.

Overview

Currently, our business operations are conducted only through ETP s Operating Partnerships, ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and natural gas storage operations, Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern), a Delaware limited liability company engaged in interstate transportation of natural gas, and ETC Midcontinent Express Pipeline, LLC (ETC MEP or MEP), a Delaware limited liability company engaged in interstate transportation of natural gas, and HOLP and Titan, both Delaware limited partnerships engaged in retail propane operations.

Parent Company Energy Transfer Equity, L.P.

The principal sources of cash flow for the Parent Company are distributions it receives from its direct and indirect investments in limited and general partner interests of ETP. The Parent Company s primary cash requirements are for general and administrative expenses, debt service and distributions to its partners. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of ETP or the Operating Partnerships.

In order to fully understand the financial condition and results of operations of the Parent Company on a stand-alone basis, we have included discussions of Parent Company matters apart from those of our consolidated group.

General

Our primary objective is to increase the level of our cash distributions to our partners over time by pursuing a business strategy that is currently focused on growing our natural gas midstream and intrastate 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 Propane Partners, L.P. 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

Canyon Gathering System in October 2007

We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional cash flow to our Unitholders for years to come. Recently, we announced the construction of the Texas Independence pipeline expected to be completed in the third quarter of 2009, as well as the completion of several projects including our Southeast Bossier pipeline in April 2008, and our San Juan Loop, Paris Loop, Maypearl to Malone and Carthage Loop projects in the third quarter of 2008. In January 2009, we completed our Southern Shale and Cleburne to Tolar pipeline projects. We also completed our Phoenix lateral pipeline in February 2009.

Our principal operations are primarily conducted in the following significant segments:

Midstream - Revenue is primarily dependent upon 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.

Intrastate transportation and storage - 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 HPL System 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.

Interstate transportation - The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

Retail propane - Revenue is generated from the sale of propane and propane-related products and services.

Summary of Operating Financial Performance in 2008

For the year ended December 31, 2008, our gross margin was $2.36 billion and operating income was $1.10 billion. During 2008, we completed several significant intrastate pipeline projects and we announced several new intrastate and interstate pipeline construction projects. In addition, we experienced increased volumes in our natural gas operations and better than expected processing margins throughout most of the year. We continue to experience significant demand from our customers for transportation capacity through our extensive pipeline network.

ETP s Operations

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 year 2008 results were significantly impacted by the completion of several pipeline projects that were completed during 2007 and 2008.

Despite the slow down in home construction, the economic recession and increased fuel prices that caused customer conservation, our propane operations were able to deliver better than expected results. Historically, as the weather becomes colder, the sales volumes and revenues would typically increase. For the year ended December 31, 2008 the weather was slightly colder than normal, but volume trends did not track as closely to weather pattern trends in 2008 due to the reasons mentioned above. Our retail propane volumes decreased due to continued conservation, but were offset by volumes added through acquisitions. We also were able to increase our sales prices during the first nine months of 2008 which improved our gross margins. Additionally, due to the acquisitions we made during 2008, our other propane segment revenues, such as appliance sales, labor and tank rentals, also improved over prior years.

From a capital resource perspective, ETP continued to secure long-term financing and successfully raised $2.10 billion in long-term debt with interest rates ranging from 6.0% to 9.70% and maturities ranging from 5 to 30 years (subject to the 3-year put option relating to the ETP 9.70% Senior Notes as described below under - Financing and Sources of Liquidity Description of Indebtedness). ETP also received net proceeds of approximately $373.0 million from the sale of its Common Units during the year ended December 31, 2008. These proceeds were used to repay borrowings under the ETP 364-Day Credit Facility (defined below) and a portion of the debt outstanding under ETP s revolving credit facility (the ETP Credit Facility).

On January 27, 2009, ETP closed a public offering of 6,900,000 Common Units representing limited partner interests at $34.05 per Common Unit. ETP used the net proceeds from the offering to repay approximately $225.9 million outstanding debt under the ETP Credit Facility. ETP expects to use some of the increased availability under the ETP Credit Facility to finance capital expenditures and other growth projects.

Trends and Outlook

The current constraints in the capital markets may affect our ability to obtain funding through new borrowings or the issuance of Common Units. In addition, we expect that, to the extent we are successful in arranging new debt financing, we will incur increased costs associated with these debt financings. In light of the current market conditions, we have taken steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate and continuing to appropriately manage operating and administrative costs to improve profitability. ETP also successfully completed a $600.0 million senior note offering in December 2008 and a 6.9 million ETP Common Unit offering in January 2009. As of December 31, 2008, in addition to approximately $91.9 million of cash on hand, we had available capacity under the Parent Company s debt facilities and the ETP Credit Facility of $1.42 billion. On a pro forma basis, as of December 31, 2008, taking into account net proceeds of approximately $225.9 million from ETP s January 2009 equity offering, available capacity under the ETP Credit Facility was $1.27 billion. We expect to utilize these resources, along with cash from operations, to fund our announced growth capital expenditures for 2009 and working capital needs during 2009. In addition to these sources of liquidity, we may also access the debt and equity markets during 2009 in order to provide additional liquidity to fund growth capital expenditures for future years or for other partnership purposes.

ETP will continue to evaluate a variety of financing sources in order to fund its future growth capital expenditures and working capital needs, including funds available under our existing revolving credit facility, funds raised from future equity and/or debt offerings and funds raised from other sources, which sources may include project financing or other alternative financing arrangements from third parties or affiliated parties. In this regard, ETP has initiated discussions with us regarding the prospect of our purchasing additional ETP Common Units from ETP. We have an aggregate of approximately $378.4 million of cash on hand and available borrowing capacity under our revolving credit facility as of December 31, 2008.

We believe that the size and scope of our operations, our stable asset base and cash flow profile and our investment grade status will be significant positive factors in our efforts to obtain new debt or equity funding; however, there is no assurance that we will be successful in obtaining financing under any of the alternatives discussed above if current capital market conditions continue for an extended period of time or if markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions, and other uncertainties.

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. In particular, our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas and NGLs have fallen dramatically since July 2008. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells.

In our intrastate and interstate natural gas operations, a significant portion of our revenue is derived from long-term fee-based arrangements pursuant to which our customers pay us capacity reservation charges regardless of the volume of natural gas transported; however, a portion of our revenue is derived from charges based on actual volumes transported. As a result, our operating cash flows from our natural gas pipeline operations are not tied directly to changes in natural gas and NGL prices; however, the volumes of natural gas we transport may be adversely affected by reduced drilling activity of our customers as a result of lower natural gas prices. As a portion of our pipeline transportation revenue is based on volumes transported, lower volumes of natural gas transported would result in lower revenue from our intrastate and interstate natural gas operations. Based on the significant level of revenue we receive from reservation capacity charges under long-term contracts and our review of the recent announcements of drilling plans by our customers, we do not expect the current level of natural gas prices to have a significant adverse effect on our operating results; however, there are no assurances that commodity prices will not decline further, which could result in a further reduction in drilling activities by our customers.

Since certain of our natural gas marketing operations and substantially all of our propane operations involve the purchase and resale of natural gas and NGLs, we expect our revenues and costs of products sold to be lower than prior periods if commodity prices remain at or fall below existing levels. However, we do not expect our margins from these activities to be significantly impacted as we typically purchase the commodity at a lower price than the sales price. Since the prices of natural gas and NGLs have been volatile, there are no assurances that we will ultimately sell the commodity for a profit.

As noted above, we may reduce our level of discretionary capital expenditures for growth projects in order to preserve our capital resources in the event that the capital market conditions do not allow us to obtain debt or equity financing on reasonable terms. In the event we do not pursue growth projects due to lack of capital, we would likely not achieve the growth in distributable cash flow as we have previously planned.

We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swaps where applicable, and to date have not had any significant credit defaults associated with our transactions. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

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 Form 10-K.

In November 2007, we changed our fiscal year end to the calendar year. Thus, our current fiscal year began on January 1, 2008. We completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. We subsequently filed audited financial statements for the four-month transition period on Form 8-K on March 19, 2008. The results of operations contained herein cover the twelve months ended December 31, 2008, the four month periods ended December 31, 2007 and 2006 and the fiscal years ended August 31, 2007 and 2006.

We did not recast the financial data for the prior fiscal periods because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Comparability between periods is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the calendar year ended December 31, 2008 are substantially similar to what is reflected in the information for the fiscal year ended August 31, 2007.

The comparability of our operations information is affected by the December 1, 2006 acquisition of Transwestern. The volumes and results of operations data for the four months ended December 31, 2007 include the interstate operations for the entire period. However, the volumes and results of operations for the four months ended December 31, 2006 include the interstate operations only from the acquisition date forward.

Historically, the comparability of our consolidated financial statements is affected by fluctuation in natural gas prices, mainly due to 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, and basis differences between market hubs.

Due to the high level of market volatility experienced in 2008, as well as other business considerations, the Partnership ceased its speculative trading activities in July 2008. As a result, the Partnership will no longer have any material exposure to market risk from these activities. Trading activities resulted in net losses of approximately $26.2 million for the year ended December 31, 2008, net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007, and net gains of approximately $2.2 million for the fiscal year ended August 31, 2007.

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The Parent Company currently has no separate operating activities apart from those conducted by ETP and its Operating Partnerships. The principal sources of cash flow for the Parent Company are its direct and indirect investments in the limited and general partner interests of ETP. The Parent Company results of operations reflect the ETE stand-alone results of operations for all periods presented below.

Year Ended December 31, 2008 Compared to the Year Ended August 31, 2007 (tabular dollar amounts are expressed in thousands)

Parent Company Only Results

The following table summarizes the key components of the stand-alone results of operations of the Parent Company for the periods indicated:

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Equity in earnings of affiliates	$ 551,835	$ 435,247	$ 116,588
Selling, general and administrative expenses	6,453	8,496	(2,043)
Interest expense	91,822	104,405	(12,583)
Losses on non-hedged interest rate derivatives	(77,435)	(1,952)	(75,483)
Other, net	(1,056)	(405)	(651)

The following is a discussion of the highlights of the Parent Company s stand-alone results of operations for the periods presented.

Equity in Earnings of Affiliates. Equity in earnings of affiliates represents earnings of the Parent Company related to its investment in limited partner units of ETP, its ownership of ETP GP and its ownership of ETP LLC. The increase in equity in earnings of affiliates was directly related to the changes in the ETP segment income described below.

Interest Expense. The Parent Company interest expense decreased primarily due to a decrease in the LIBOR rate between the periods.

Gains (Losses) on Non Hedged Interest Rate Derivatives. The Parent Company has interest swaps with a notional amount of $800.0 million that are not accounted for as hedges under SFAS 133. Changes in the fair value of these swaps are recorded directly in earnings. The variable portion of these swaps are based on the three month LIBOR and its corresponding forward curve. A decrease in these rates between the comparable periods resulted in decreases in the swaps fair value and settlement amounts during the year ended December 31, 2008 compared with the year ended August 31, 2007.

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Consolidated Results

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Revenues	$ 9,293,367	$ 6,792,037	$ 2,501,330
Cost of products sold	6,938,080	5,078,206	1,859,874
Gross margin	2,355,287	1,713,831	641,456
Operating expenses	781,831	559,600	222,231
Depreciation and amortization	274,372	191,383	82,989
Selling, general and administrative	200,181	153,512	46,669
Operating income	1,098,903	809,336	289,567
Interest expense, net of interest capitalized	(357,541)	(279,986)	(77,555)
Equity in earnings (losses) of affiliates	(165)	5,161	(5,326)
Gain (loss) on disposal of assets	(1,303)	(6,310)	5,007
Gains (losses) on non-hedged interest rate derivatives	(128,423)	29,081	(157,504)
Allowance for equity funds used during construction	63,976	4,948	59,028
Other, net	8,115	1,129	6,986
Income tax expense	(3,808)	(11,391)	7,583
Minority interests	(304,710)	(232,608)	(72,102)
Net income	$ 375,044	$ 319,360	$ 55,684

See the detailed discussion of revenues, cost of products sold, gross margin and operating expense by operating segment below.

Interest Expense. Interest expense increased principally due to higher levels of borrowings which were used to finance growth capital expenditures in our intrastate transportation and storage and interstate transportation operations.

Equity in Earnings (Losses) of Affiliates. The decrease in equity in earnings (losses) of affiliates is primarily due to the recognition of $5.1 million of equity income from our 50% ownership of CCEH during September 1, 2006 through December 1, 2006. We redeemed our investment in CCEH in connection with our Transwestern acquisition on December 1, 2006; therefore, no amounts are reflected in equity in earnings (losses) of affiliates with respect to CCEH after that date.

Gain (Loss) on Non-Hedged Interest Rate Derivatives. The Partnership had interest rate swaps at December 31, 2008 and August 31, 2007, with notional amounts of $1.43 billion and $0.93 billion, respectively, that were not designated as hedges under SFAS 133. Changes in the value of these swaps were recorded directly in earnings. The variable portion of these swaps were based on the three month LIBOR and its corresponding forward curve. A decrease in these rates during the comparable period resulted in decreases in the swaps fair value and settlement amounts during the year ended December 21, 2008 compared with the year ended August 31, 2007. In addition, the Partnership recorded a gain of $31.5 million on the settlement of a forward starting swap during the period ended August 31, 2007.

Allowance for Equity Funds Used During Construction. The increase between comparable twelve month periods is due to construction within our interstate transportation segment, which is primarily related to the Phoenix Expansion project that was subsequently completed in February 2009.

Other, Net. The increase between the comparable twelve month periods is principally due to $7.1 million from the excess of contributions in aid of construction costs (CIAC) related to $40.0 million reimbursement in connection with an extension on our Southeast Bossier pipeline (see Note 3 to our consolidated financial statements).

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

The decrease in income tax expense was primarily due to a $12.0 million tax benefit associated with a trading loss incurred by one of our corporate subsidiaries in July 2008. This tax benefit was offset by higher taxes resulting from increased earnings during the year. For additional information related to income tax expense, see Note 9 to our consolidated financial statements.

Minority Interests. The increase in minority interest expense is attributable to the increase in income from continuing operations of ETP described below that is allocated to the minority unitholders of our subsidiaries. The minority interest expense primarily represents limited partnership interests in ETP that we do not own.

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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 15 to our consolidated financial statements.

Operating income by segment is as follows:

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Midstream	$ 162,471	$ 119,233	$ 43,238
Intrastate Transportation and Storage	710,070	479,820	230,250
Interstate Transportation	124,676	95,650	29,026
Retail Propane	114,564	124,263	(9,699)
Other	(2,032)	1,735	(3,767)
Unallocated selling, general and administrative expenses	(10,846)	(11,365)	519
Operating income	$ 1,098,903	$ 809,336	$ 289,567

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 in December 2006, selling, general and administrative expenses are now allocated monthly to the Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC). The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month.

Midstream

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Natural gas MMBtu/d - sold	1,269,724	941,140	328,584
NGLs Bbls/d - sold	25,939	17,907	8,032
Revenues	$ 5,342,393	$ 2,853,496	$ 2,488,897
Cost of products sold	4,986,495	2,632,187	2,354,308
Gross margin	355,898	221,309	134,589
Operating expenses	82,872	39,148	43,724
Depreciation and amortization	63,287	27,331	35,956
Selling, general and administrative	47,268	35,597	11,671
Segment operating income	$ 162,471	$ 119,233	$ 43,238

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Gross Margin. Midstream gross margin increased between periods was primarily due to the following factors:

- An increase in fee-based revenue and processing margin of $82.9 million and $55.6 million, respectively, from our gathering and processing assets (other than our Canyon Gathering System). The increase was due to incremental volumes from the expansion of the Godley plant since placing it into service as well as favorable market conditions to process and extract NGLs;

- Incremental margin of $25.1 million due to the acquisition of the Canyon Gathering System in October 2007; and,

- A net decrease of $24.7 million in margin from our trading and marketing activities. Net realized and unrealized trading losses were $26.2 million for the year ended December 31, 2008, compared to a net gain of $2.2 million for the year ended August 31, 2007. The loss for the year ended December 31, 2008 was due to unfavorable market conditions. Other marketing activities resulted in a margin of $23.3 million for the year ended December 31, 2008 compared to $19.6 million for the year ended August 31, 2007.

Operating Expenses. Midstream operating expenses increased primarily due to increased employee-related costs of $10.2 million, increased plant operating expenses of $5.1 million, increased ad valorem tax of $3.2 million, increased compressor rental expense of $3.1 million, increased chemicals expense of $3.1 million, increased vehicles expense of $1.8 million, and increases in other expenses of $5.8 million. These increases were primarily due to the expansion of the Godley plant and the acquisition of the Canyon Gathering System in October 2007. In addition, operating expenses for the year ended December 31, 2008 includes an $11.4 goodwill impairment loss associated with the Canyon Gathering System.

Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses increased primarily due to increased employee-related costs of $16.7 million, an increase of $4.2 million in measurement and technology-related expenses, offset by a $7.3 million decrease in allocated legal fees and a decrease of $8.3 million in allocated administrative overhead expenses. Other expenses increased by a net $6.4 million. Effective January 1, 2008, we began allocating legal costs related to regulatory matters among the midstream and transportation and storage segments. During the year ended August 31, 2007, all legal costs related to regulatory matters were recorded in the midstream segment.

Depreciation and Amortization. Midstream depreciation and amortization expense increased between periods primarily due to incremental depreciation related to the Canyon Gathering System acquisition in October 2007 and the continued expansion of the Godley plant.

Intrastate Transportation and Storage

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Natural gas MMBtu/d - transported	11,187,327	6,124,423	5,062,904
Natural gas MMBtu/d - sold	1,389,781	1,400,753	(10,972)
Revenues	$ 5,634,604	$ 3,915,932	$ 1,718,672
Cost of products sold	4,467,552	3,137,712	1,329,840
Gross margin	1,167,052	778,220	388,832
Operating expenses	287,515	181,133	106,382
Depreciation and amortization	92,979	64,423	28,556
Selling, general and administrative	76,488	52,844	23,644
Segment operating income	$ 710,070	$ 479,820	$ 230,250

Gross Margin. The increase in intrastate transportation and storage gross margin between periods was comprised of the following factors:

Overall volumes on our transportation pipelines were higher due to increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, increased demand for natural gas used by electricity-producing power plants connected to our assets and the completion of several pipeline expansion projects. The increase in transport volumes were also due to favorable market conditions between the Waha and Katy/Houston Ship Channel market hubs resulting in higher volumes and higher average rates on our intrastate pipeline systems. Transportation fees increased approximately $281.3 million for the year ended December 31, 2008 as compared to the year ended August 31, 2007. Fuel retention revenue increased approximately $130.3 million due to increased volumes transported through our transportation pipelines;

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Higher natural gas prices resulting in additional retention margin of $35.8 million. Our average natural gas prices for retained fuel increased to an average of $9.66/MMBtu during the year ended December 31, 2008 from an average of $6.69/MMBtu during the year ended August 31, 2007; and,

A decrease in natural gas storage-related margin of $51.3 million. Realized margin, comprised of both margin on the withdrawal and sale of natural gas and realized gains on derivative instruments related to our storage operations, decreased by $79.2 million for the year ended December 31, 2008 compared to the year ended August 31, 2007. During the year ended December 31, 2008, there were physical sales of 39.5 Bcf of natural gas from our Bammel storage facility compared to 67.6 Bcf in the 2007 period. In addition, between the comparable twelve month periods, there was an increase of $13.1 million in storage fees, primarily due to a new contract that commenced on April 1, 2007 at our Bammel storage facility. Furthermore, we recognized unrealized mark-to-market gains related to our storage operations (which represent the change in the fair value of derivative instruments not designated as hedges for accounting purposes) of $68.2 million during the year ended December 31, 2008 compared to $5.6 million during the year ended August 31, 2007. The amount that we will ultimately realize, however, is subject to change as commodity prices change in future months and the underlying physical transaction occurs. In addition, we recognized a net lower-of-cost-or-market adjustment of $47.8 million related to natural gas stored in our Bammel facility during the year ended December 31, 2008.

Operating Expenses. Intrastate transportation and storage operating expenses increased between periods primarily due to increased fuel consumption of $90.4 million, increased utility expenses of $10.5 million, increased compressor maintenance expenses of $7.5 million, increased pipeline maintenance expenses of $7.5 million and increased employee costs of $7.5 million. These increases were offset by decreases of $11.4 million in compressor rental expense as well as a $5.6 million decrease in measurement fees.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased between primarily due to an increase of $15.7 million in allocated legal fees and an increase in other allocated costs of $8.3 million. Effective January 1, 2008, we began allocating legal costs related to regulatory matters equally between the midstream and transportation and storage segments. During the year ended August 31, 2007, all legal costs related to regulatory matters were recorded in the midstream segment.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased between periods primarily due to the continuing expansion of our pipeline system, most notably the Southeast Bossier and Maypearl to Malone pipelines.

Interstate Transportation

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Natural gas MMBtu/d - transported	1,777,097	1,802,109	(25,012)
Natural gas MMBtu/d - sold	15,162	19,680	(4,518)
Revenues	$ 244,224	$ 178,663	$ 65,561
Operating expenses	56,906	36,295	20,611
Depreciation and amortization	37,790	27,972	9,818
Selling, general and administrative	24,852	18,746	6,106
Segment operating income	$ 124,676	$ 95,650	$ 29,026

For all categories above, the increase between the year ended December 31, 2008 and the year ended August 31, 2007 is primarily due to the results for the year ended August 31, 2007 only including nine months of activity from the date of the Transwestern acquisition (December 1, 2006). The results for the year ended December 31, 2008 include the entire twelve months.

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Retail Propane

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Retail propane gallons sold (in thousands)	601,134	604,269	(3,135)
Retail propane revenues	$ 1,514,599	$ 1,179,073	$ 335,526
Other retail propane related revenues	109,411	105,794	3,617
Retail propane cost of products sold	1,014,068	734,204	279,864
Other retail propane related cost of products sold	24,654	25,430	(776)
Gross margin	585,288	525,233	60,055
Operating expenses	350,280	297,469	52,811
Depreciation and amortization	79,717	70,833	8,884
Selling, general and administrative	40,727	32,668	8,059
Segment operating income	$ 114,564	$ 124,263	$ (9,699)

Volumes. The slight decrease in gallons sold for the year ended December 31, 2008 compared to the year ended August 31, 2007 was primarily due to the continued conservation from customers over the past twelve months, offset by the volumes added through acquisitions after August 31, 2007. For the year ended December 31, 2008 the weather was 5.3% colder than the year ended August 31, 2007, but volume trends did not track as closely to weather pattern trends in 2008 due to the slow down in new home construction, the economic recession and increased fuel prices that caused the aforementioned customer conservation.

Revenues. Retail propane revenues increased 28.5% or $335.5 million in the year ended December 31, 2008 as compared to the year ended August 31, 2007. The retail propane revenue variance between these periods was principally impacted by the increase in propane selling prices in the later period presented to keep pace with the increases in the wholesale price of propane. The average sales price per retail gallon sold increased approximately 29.1% for the year ended December 31, 2008 compared to the year ended August 31, 2007.

Cost of Products Sold. Retail propane cost of products sold increased significantly due to the increase in the average fuel price purchased for resale during 2008. While fuel prices significantly declined during the last three months of the year ended December 31, 2008, but the overall price per gallon for the year ended December 31, 2008 was 38.8% higher than the year ended August 31, 2007. In addition, we entered into propane sales commitments with a portion of our retail customers that provide for a contracted price agreement for a specified period of time, typically no longer than one year. These commitments can expose the operations to product price risk if not offset by a propane purchase commitment. To hedge a significant portion of these sales commitments, we utilize financial instruments (swap agreements) as purchase commitments to lock in the margins. These financial instruments were not designated as hedges for accounting purposes, and the change in market value was recorded in cost of products sold in the consolidated statements of operations. The cost of products sold for the propane operations was negatively impacted by the decline in propane prices from the time the agreements were entered into. Unrealized losses of $45.6 million were recorded through cost of products sold during the year ended December 31, 2008, on these financial instruments. There were minimal losses during the year ended August 31, 2007.

Gross Margin. The increase in gross margins was principally due to our ability to manage retail selling prices despite the decrease in wholesale propane prices, particularly in the latter part of 2008. The retail fuel gross margins were $0.0966 per gallon higher for the year ended December 31, 2008 as compared to the year ended August 31, 2007 primarily due to the aforementioned, offset by the accounting impact of the unrealized losses recorded on financial instruments as noted above.

Operating Expenses. Operating expenses increased between the comparable periods due to various factors. Although volumes were relatively flat, vehicle fuel and lube used for delivery to customers increased $10.7 million primarily due to the increase in the average fuel costs between the comparable periods. Wages, deferred compensation and other employee benefits increased $24.5 million due to an increase in headcount as a result of acquisitions and cost of living increases were given to existing employees. The employee-related increases were offset by savings from delays in hiring seasonal employees due to volume pressures described above. Bad debt expense has increased a net $4.2 million as the general economy has also shown pressure on the collection of receivables leading to a decision to increase accounts receivable reserves. Our operational employee incentive program was $7.2 million higher for the year ended December 31, 2008 as compared to August 31, 2007, due to more favorable results achieved during the year ended December 31, 2008 than during the year ended August 31, 2007.

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Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses between the comparable periods was primarily due to increased administrative expense allocations of $2.4 million, increases in wages, deferred compensation and other employee related benefits of $2.7 million, and consulting and other costs related to information technology systems implementations and non-recurring costs related to property settlements in 2008.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense between the comparable periods was primarily due to the incremental expense resulting from acquisitions made subsequent to August 31, 2007.

Four Months Ended December 31, 2007 compared to the Four Months Ended December 31, 2006 (unaudited tabular dollar amounts in thousands)

In November 2007, we changed our fiscal year end from August 31 to December 31 and, in connection with such change, we are including comparative financial results for the four-month transition period of September 1, 2007 to December 31, 2007.

Parent Company Only Results

The following table summarizes the key components of the stand-alone results of operations of the Parent Company for the periods indicated:

	Four Months Ended December 31,		Amount of
	2007	**2006**	**Change**
Equity in earnings of affiliates	$ 168,547	$ 107,586	$ 60,961
Selling, general and administrative expenses	2,875	3,131	(256)
Interest expense	37,071	28,026	9,045
Losses on non-hedged interest rate derivatives	(27,670)		(27,670)
Other, net	(8,128)	252	(8,380)

The following is a discussion of the highlights of the Parent Company s stand-alone results of operations for the periods presented.

Equity in Earnings of Affiliates. Equity in earnings of affiliates represents earnings of the Parent Company related to its investment in limited partner units of ETP, its ownership of ETP GP and its ownership of ETP LLC. The increase in equity in earnings of affiliates was directly related to the changes in the ETP segment income described below.

Interest Expense. The Parent Company interest expense increased because the Parent Company entered into a $1.30 billion Senior Secured Term Loan Facility on November 1, 2006. Such borrowings were outstanding for the entire four months ended December 31, 2007.

Losses on Non-Hedged Interest Rate Derivatives. See discussion below in Other, net.

Other, Net. The change in other, net was due primarily to losses of $27.7 million on changes in value of interest rate swaps that are not accounted for as hedges. Such gains and losses were included in interest expense during the four months ended December 31, 2006. The four months ended December 31, 2007 also included an expense of $7.8 million for liquidated damages under the registration rights agreements for the March 2007 and November 2006 private placement of ETE Common Units (as described in Note 7 to our consolidated financial statements).

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Consolidated Results

	Four Months Ended December 31, 2007	2006	Amount of Change
Revenues	$ 2,349,342	$ 2,162,466	$ 186,876
Cost of products sold	1,673,654	1,689,843	(16,189)
Gross margin	675,688	472,623	203,065
Operating expenses	221,757	173,365	48,392
Depreciation and amortization	75,406	52,840	22,566
Selling, general and administrative	61,874	43,602	18,272
Operating income	316,651	202,816	113,835
Interest expense, net of interest capitalized	(103,375)	(82,979)	(20,396)
Equity in earnings (losses) of affiliates	(94)	4,743	(4,837)
Gain (loss) on disposal of assets	14,310	2,212	12,098
Other, net	(34,734)	2,248	(36,982)
Income tax expense	(9,949)	(2,155)	(7,794)
Minority interests	(90,132)	(50,204)	(39,928)
Net income	$ 92,677	$ 76,681	$ 15,996

See the detailed discussion of revenues, cost of products sold, margin and operating expense by operating segment below.

Interest Expense. Interest expense increased $20.4 million principally due to a net $9.0 million increase in interest expense related to borrowings of the Parent Company, a net $13.8 million increase in interest expense related to increased borrowings on ETP s Senior Notes and the ETP Credit Facility and $0.5 million of interest on borrowings related to the Transwestern acquisition. Partnership borrowings increased primarily due to the financing of our growth capital expenditures and the Canyon acquisition. The increased interest expense was offset by $2.0 million of unrealized losses related to non-hedged interest rate swaps included in interest expense for the four months ended December 31, 2006. Unrealized gains and losses related to non-hedged interest rate swaps were included in other income (expense), net for the four months ended December 31, 2007. The increase in interest expense was also offset by propane related interest which decreased $2.0 million due primarily to the scheduled debt payments that have occurred between the four-month periods.

Equity in Earnings of Affiliates. The decrease in equity in earnings (losses) of affiliates was due primarily to $5.1 million of equity income from our 50% ownership of the member interests in CCE Holdings, LLC (CCEH) for the month of November 2006. We redeemed our investment in CCEH in connection with our Transwestern acquisition on December 1, 2006. We do not include earnings from equity method unconsolidated affiliates in our measurement of operating income because such earnings have not been significant historically.

Gain on Sale of Assets. On October 1, 2007 we sold our 60% interest in a Canadian wholesale fuel business for a gain of $10.2 million.

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

The increase in income tax expense was primarily related to $3.9 million recorded for the four months ended December 31, 2007 of Texas margin tax that was not effective until January 1, 2007 and $3.9 million of taxes on the gain on the sale of our interest in a Canadian wholesale fuel business.

Losses on Non-Hedged Interest Rate Derivatives. See discussion below in Other, Net.

Other, Net. The change in other, net, was due to the factors discussed above for the Parent Company results.

Minority Interests. The increase in minority interest expense in the four months ended December 31, 2007 is attributable to the increase in income from continuing operations of ETP described below that is allocated to the minority unitholders of our subsidiaries. The minority interest expense primarily represents limited partnership interests in ETP that we do not own.

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Segment Operating Results

Operating income by segment is as follows:

	Four Months Ended December 31, 2007	2006	Amount of Change
Midstream	$ 71,853	$ 40,421	$ 31,432
Intrastate Transportation and Storage	169,361	109,262	60,099
Interstate Transportation	29,657	11,854	17,803
Retail Propane	46,747	49,841	(3,094)
Other	(796)	528	(1,324)
Unallocated selling, general and administrative expenses	(171)	(9,090)	8,919
Operating income	$ 316,651	$ 202,816	$ 113,835

We do not believe the Other operating income is material for further disclosure 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 monthly to the Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC). The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the estimated allocation and actual costs is adjusted in the following month. For the four months ended December 31, 2007, a net $12.1 million allocation to the Operating Partnerships exceeded total incurred costs.

Midstream

	Four Months Ended December 31, 2007	2006	Amount of Change
Natural gas MMBtu/d - sold	1,090,090	968,016	122,074
NGLs Bbls/d - sold	25,389	12,458	12,931
Revenues	$ 1,166,313	$ 905,392	$ 260,921
Cost of products sold	1,043,191	839,561	203,630
Gross margin	123,122	65,831	57,291
Operating expenses	17,633	11,710	5,923
Depreciation and amortization	14,943	7,748	7,195
Selling, general and administrative	18,693	5,952	12,741
Segment operating income	$ 71,853	$ 40,421	$ 31,432

Gross Margin. Midstream s gross margin increased between comparable periods primarily due to the following factors:

Increases in processing margin of $37.6 million and fee-based revenue of $17.9 million from our gathering and processing assets. The increase was due to incremental volumes from the completion of our Godley plant in October 2006, the continued expansion of the plant since placing it into service, and the acquisition of three gathering systems during the first six months of the 2007 fiscal year. In addition, our midstream assets benefited from favorable market conditions to process and extract NGLs during the four months ended December 31,

2007. Due to changes in the contract structures at our Godley plant, arrangements for which we had been recognizing the increased margin from favorable conditions converted to long-term fee-based contracts in November 2007. As such, we expect margin from processing at our Godley plant to be more predictable and less sensitive to commodity price volatility. As of December 31, 2007, the Godley plant had approximately 500 MMcf/d of cryoprocessing capacity and 100 MMcf/d of dew point processing capacity;

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Increase in non-trading margin from our marketing activities of $1.0 million as market conditions resulted in higher sales volumes conducted by our producer services operations;

Decrease in net trading revenues of $5.2 million; and,

Canyon Gathering System The acquisition of the Canyon Gathering System on October 5, 2007 contributed approximately $5.6 million of incremental margin for the four months ended December 31, 2007.

Operating Expenses. Midstream operating expenses increased $5.9 million, primarily driven by increased employee-related costs such as salaries, incentive compensation and healthcare costs of $2.2 million, increased compressor rentals of $1.5 million, and increased pipeline and compressor maintenance expense of $0.7 million. The increases were principally due to the gathering system acquisitions in fiscal 2007, the start up and continued expansion of the Godley plant, and the Canyon acquisition.

Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses increased $12.7 million which was attributable to $9.2 million in increased legal fees principally related to regulatory matters, a $4.2 million allocation of parent company administrative expenses for overhead costs that previously had not been allocated in 2006, and a $1.9 million increase in employee-related costs such as salaries, incentive compensation and healthcare costs. These factors were offset by a $5.8 million increase of general and administrative expenses allocated to the transportation segment. The allocation of general and administrative expenses between the midstream and the intrastate transportation and storage segments is based on the MMFC and is intended to fairly present the segment s operating results.

Depreciation and Amortization. Midstream depreciation and amortization expense increased $7.2 million principally due to additions to property and equipment including the completion and continued expansion of our Godley plant, and the acquisition of certain gathering systems in 2006.

Intrastate Transportation and Storage

	Four Months Ended December 31,		Amount of
	2007	**2006**	**Change**
Natural gas MMBtu/d - transported	8,787,387	4,889,029	3,898,358
Natural gas MMBtu/d - sold	1,259,566	1,379,721	(120,155)
Revenues	$ 1,254,401	$ 1,195,871	$ 58,530
Cost of products sold	964,568	994,511	(29,943)
Gross margin	289,833	201,360	88,473
Operating expenses	76,428	56,452	19,976
Depreciation and amortization	23,429	19,020	4,409
Selling, general and administrative	20,615	16,626	3,989
Segment operating income	$ 169,361	$ 109,262	$ 60,099

Volumes and Gross Margin. Increases in intrastate transportation and storage volumes and gross margin are comprised of the following factors:

Transported natural gas volumes increased principally due to the increased volumes experienced on the ET Fuel and East Texas Pipeline systems as a result of the completion of the Cleburne to Carthage Pipeline, increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, and the continued effort to secure long-term shipper contracts.

Natural gas sales volumes on the HPL System decreased primarily 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.

Transportation fees increased approximately $53.2 million. Retention revenue increased approximately $29.7 million due to increased volumes transported through our transportation pipelines;

Increase in processing margin of $8.6 million from our HPL system. Processing margins generated from our HPL system benefited from favorable market conditions to process and extract NGLs during the four months ended December 31, 2007; and

Net decrease in storage margins of $9.4 million. During the four months ended December 31, 2006, we recognized approximately $27.0 million of margin on 13 Bcf of gas sold from our Bammel facility. Due to market conditions, there were no withdrawals in the same period in 2007; however, we did recognize $9.2 million in gains from the discontinuation of hedge accounting resulting from our determination that originally forecasted sales of natural gas from the Partnership s Bammel storage facility were no longer probable to occur by the specified time period, or within an additional two-month time period thereafter. In addition, fee-based storage revenues increased $8.4 million primarily due to the new Centerpoint contract which commenced on April 1, 2007 in which Centerpoint contracted for 10 Bcf of working gas capacity in our Bammel storage facility.

Operating Expenses. Intrastate transportation and storage operating expenses increased $20.0 million primarily due to an increase of $11.4 million in fuel consumption, an increase of $4.5 million in electricity costs, an increase of $6.1 million in compressor and pipeline maintenance, and an increase of $2.0 million in employee related costs such as salaries, incentive compensation and healthcare costs. These increases were offset by a $2.8 million decrease in compressor rentals and a $2.9 million decrease in professional fees related to the EMS contract buyout in September 2007.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased $4.0 million principally due to an increase in general and administrative expenses allocated from the midstream segment as noted above.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased $4.4 million principally due to additions to property and equipment most notably the Cleburne to Carthage Pipeline.

Interstate Transportation

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Amount of Change
Natural gas MMBtu/d - transported	1,708,477	1,822,065	(113,588)
Natural gas MMBtu/d - sold	13,663	14,104	(441)
Revenues	$ 76,000	$ 19,003	$ 56,997
Operating expenses	23,922	1,396	22,526
Depreciation and amortization	12,305	3,191	9,114
Selling, general and administrative	10,116	2,562	7,554
Segment operating income	$ 29,657	$ 11,854	$ 17,803

The increase in all categories was attributable to the Transwestern acquisition on December 1, 2006.

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Retail Propane

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Amount of Change
Retail propane gallons sold (in thousands)	205,311	214,623	(9,312)
Retail propane revenues	$ 471,494	$ 409,821	$ 61,673
Other retail propane related revenues	39,764	40,020	(256)
Retail propane cost of products sold	315,698	256,994	58,704
Other retail propane related cost of products sold	9,460	10,344	(884)
Gross margin	186,100	182,503	3,597
Operating expenses	102,537	101,508	1,029
Depreciation and amortization	24,537	22,520	2,017
Selling, general and administrative	12,279	8,634	3,645
Segment operating income	$ 46,747	$ 49,841	$ (3,094)

Volumes. Total gallons sold by our retail propane operations decreased due to a combination of below normal degree days, customer conservation, and the slow down of new home construction in our propane markets. The overall weather in our areas of operations during the four months ended December 31, 2007 was 2.9% warmer than the four months ended December 31, 2006 and 9.8% warmer than normal.

Revenues. Retail propane revenues increased $61.7 million mainly due to increased sale prices driven by the increased cost of fuel. This increase was offset by 9.8% warmer than normal weather and 2.9% warmer weather than the same period last year.

Cost of Products Sold. Retail propane cost of products sold increased by $58.7 million mainly related to the increase in overall cost of fuel to the company offset by the decrease in gallons sold. On an average, fuel costs were approximately $0.35/gallon higher.

Gross Margin. Overall gross margins increased $3.6 million even though gallon sales decreased. The propane margin remained strong despite warmer weather conditions and higher fuel prices. Optimization of the margins is influenced by market opportunities, independent competitors and concerns for long term retention of customers.

Operating Expenses. Operating expenses increased by $1.0 million. Included in these operating expenses were increases related to higher vehicle fuel costs and other vehicle expenses, offset by the cost conservation efforts of the retail operations and the delay in hiring seasonal staff due to the warmer weather.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses was primarily due to increased administrative expense allocations. Effective with the Transwestern acquisition in December 2006, an allocation of general and administrative expenses based on the MMFC is now made to the operating partnerships, which increased the retail propane selling, general and administrative expenses by a net $5.1 million for the four months ended December 31, 2007. This increase from the allocation of expenses was offset by the reduction of certain personnel costs at the propane operating partnerships.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense was primarily due to the depreciation and amortization of assets and amortizable intangibles added through acquisitions made after December 31, 2006.

Fiscal Year Ended August 31, 2007 compared to Fiscal Year Ended August 31, 2006 (tabular dollar amounts in thousands)

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Parent Company Only Results

The following table summarizes the key components of the stand-alone results of operations of the Parent Company for the periods indicated:

	Years Ended August 31,		Amount of
	2007	**2006**	**Change**
Equity in earnings of affiliates	$ 435,247	$ 204,987	$ 230,260
Selling, general and administrative expenses	8,496	55,374	(46,878)
Interest expense	104,405	36,773	67,632
Loss on extinguishment of debt		5,060	(5,060)
Losses on non-hedged interest rate derivatives	(1,952)		(1,952)
Other, net	(405)	(638)	233

The following is a discussion of the highlights of the Parent Company s stand-alone results of operations for the periods presented.

Equity in Earnings of Affiliates. Equity in earnings of affiliates represents earnings of the Parent Company related to its investment in limited partner units of ETP, its Class A and Class B limited partner interests of ETP GP and its investment in ETP LLC. The increase in equity in earnings of affiliates for the year ended August 31, 2007 compared to the year ended August 31, 2006 was directly related to the increased ownership in ETP as a result of the Common, Class F and Class G Unit acquisitions in February 2006 and November 2006 and the increased ownership of ETP IDRs, as discussed above, and the changes in the ETP segment income described below.

The change in the Parent Company s ownership share of ETP during fiscal years 2007 and 2006 was as follows:

	Limited Partner Interest	IDRs	General Partner Interest
Interest as of December 2005	31%	50%	2%
Purchase of ETP Common and Class F			
Units in February 2006	2%		
Purchase of ETP Class G Units in November 2006	13%		
Purchase of IDRs from ETI in November 2006		50%	
interests as of August 31, 2007	46%	100%	2%

General and Administrative Expenses. The decrease in general and administrative expenses of the Parent Company for the year ended August 31, 2007 compared to the year ended August 31, 2006 and the increase in general and administrative expenses for the year ended August 31, 2006 compared to the year ended August 31, 2005 is primarily due to the compensation expense of $52.9 million recorded in fiscal year 2006 in connection with the issuance of Class B Units by the Parent Company in conjunction with its IPO. (See Note 7 to our consolidated financial statements).

Interest Expense. The Parent Company interest expense increased for the year ended August 31, 2007 compared to 2006 primarily due to the increased borrowings to fund the acquisition of Class G units from ETP in November 2006. Please read Description of Indebtedness under Liquidity and Capital Resources and Note 6 to our consolidated financial statements for more information on the Parent Company s indebtedness.

Loss on Extinguishment of Debt. The Parent Company expensed $5.1 million in deferred financing costs during fiscal year 2006 in connection with the repayment of the $600.0 million senior secured term loan agreement as described above. There was no similar repayment during fiscal year 2007.

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Consolidated Results

	Years Ended August 31, 2007	2006	Amount of Change
Revenues	$ 6,792,037	$ 7,859,096	$ (1,067,059)
Cost of products sold	5,078,206	6,568,316	(1,490,110)
Gross margin	1,713,831	1,290,780	423,051
Operating expenses	559,600	422,989	136,611
Depreciation and amortization	191,383	129,636	61,747
Selling, general and administrative	153,512	162,615	(9,103)
Operating income	809,336	575,540	233,796
Interest expense, net of interest capitalized	(279,986)	(150,646)	(129,340)
Loss on extinguishment of debt		(5,060)	5,060
Equity in earnings (losses) of affiliates	5,161	(479)	5,640
Gain (loss) on disposal of assets	(6,310)	851	(7,161)
Other, net	35,158	13,701	21,457
Income tax expense	(11,391)	(23,015)	11,624
Minority interests	(232,608)	(303,752)	71,144
Net income	$ 319,360	$ 107,140	$ 212,220

See the detailed discussion of revenues, cost of products sold, gross margin and operating expense by operating segment below.

Interest Expense. Interest expense increased between the comparable periods principally due to a net $67.6 million increase in interest expense related to borrowings of the Parent Company, a net $51.2 million increase in interest expense related to borrowings from ETP s offerings of Senior Notes and the ETP 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 losses of $0.1 million on interest rate swaps were recorded as an increase to interest expense. Such activity was not recognized in interest expense in the year ended August 31, 2007; rather, such activity was 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 12 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.

Loss on Extinguishment of Debt. The loss on extinguishment of debt during fiscal year 2006 is discussed above under Parent Company Only Results.

Equity in Earnings of Affiliates. The increase in equity in earnings of affiliates between the comparable periods 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 resulted from the sale of a compressor station.

Other, Net. The increase in interest and other income between the comparable periods 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 Note 7 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.

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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 2007. The decrease was partially offset by the Texas margin tax that was not effective until January 1, 2007.

Minority Interest Expense from Continuing Operations. The decrease in minority interest expense in fiscal year 2007 is attributable to the Parent Company s acquisition of ETP limited partner interests in November 2006 (discussed above), offset by the increase in income from continuing operations of ETP described below that is allocated to the minority unitholders of our subsidiaries. The minority interest expense primarily represents partnership interests in ETP that we do not own.

The increase in minority interest expense in fiscal year 2006 is attributable to the increase in income from continuing operations of ETP described below that is allocated to the minority unitholders of our subsidiaries. The minority interest expense primarily represents partnership interests in ETP that we do not own.

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 15 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
	2007	**2006**	**Change**
Midstream	$ 119,233	$ 147,564	$ (28,331)
Intrastate Transportation and Storage	479,820	422,420	57,400
Interstate Transportation	95,650		95,650
Retail Propane	124,263	76,055	48,208
Other	1,735	1,899	(164)
Unallocated selling, general and administrative expenses	(11,365)	(72,398)	61,033
Operating income	$ 809,336	$ 575,540	$ 233,796

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.

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Midstream

	Years Ended August 31, 2007	2006	Amount of Change
Natural gas MMBtu/d - sold	941,140	1,552,753	(611,613)
NGLs Bbls/d - sold	25,657	10,425	15,232
Revenues	$ 2,853,496	$ 4,223,544	$ (1,370,048)
Cost of products sold	2,632,187	4,000,461	(1,368,274)
Gross margin	221,309	223,083	(1,774)
Operating expenses	39,148	31,910	7,238
Depreciation and amortization	27,331	19,687	7,644
Selling, general and administrative	35,597	23,922	11,675
Segment operating income	$ 119,233	$ 147,564	$ (28,331)

Volumes. 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 marketing 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.

Gross Margin. 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 marketing 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.

Operating Expenses. The increase in midstream operating expenses 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.

Selling, General and Administrative Expenses. The midstream general and administrative expenses increase was primarily due to a $13.2 million increase in 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.

Depreciation and Amortization. Midstream depreciation and amortization expense increased during the comparable periods primarily 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.

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Intrastate Transportation and Storage

	Years Ended August 31, 2007	2006	Amount of Change
Natural gas MMBtu/d - transported	6,124,423	4,633,069	1,491,354
Natural gas MMBtu/d - sold	1,400,753	1,580,638	(179,885)
Revenues	$ 3,915,932	$ 5,013,224	$ (1,097,292)
Cost of products sold	3,137,712	4,322,217	(1,184,505)
Gross margin	778,220	691,007	87,213
Operating expenses	181,133	171,312	9,821
Depreciation and amortization	64,423	50,755	13,668
Selling, general and administrative	52,844	46,520	6,324
Segment operating income	$ 479,820	$ 422,420	$ 57,400

Volumes and Gross Margin. Intrastate transportation and storage gross margin increased between the comparable periods by $87.2 million principally due to the net effect of the following:

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. 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.

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.

Operating Expenses. Intrastate transportation and storage operating expenses increased between comparable periods primarily due 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.

Selling, General and Administrative Expenses. Intrastate transportation and storage general and administrative expenses increased between comparable periods primarily 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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Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased between comparable periods primarily due to plant and equipment placed into service during fiscal year 2007.

Interstate Transportation

	Years Ended August 31, 2007	2006	Amount of Change
Natural gas MMBtu/d - transported	1,802,109		1,802,109
Natural gas MMBtu/d - sold	19,680		19,680
Revenues	$ 178,663	$	$ 178,663
Operating expenses	36,295		36,295
Depreciation and amortization	27,972		27,972
Selling, general and administrative	18,746		18,746
Segment operating income	$ 95,650	$	$ 95,650

The increase in all categories between fiscal years ended August 31, 2007 and 2006 was attributable to the Transwestern acquisition on December 1, 2006.

Retail Propane

	Years Ended August 31, 2007	2006	Amount of Change
Retail propane gallons sold (in thousands)	604,269	429,118	175,151
Retail propane revenues	$ 1,179,073	$ 799,358	$ 379,715
Other retail propane related revenues	105,794	80,198	25,596
Retail propane cost of products sold	734,204	493,642	240,562
Other retail propane related cost of products sold	25,430	21,776	3,654
Gross margin	525,233	364,138	161,095
Operating expenses	297,469	212,188	85,281
Depreciation and amortization	70,833	58,036	12,797
Selling, general and administrative	32,668	17,859	14,809
Segment operating income	$ 124,263	$ 76,055	$ 48,208

Volumes. The retail propane operations realized significant increases (a 175.2 million net gallon increase) in gallons sold between comparable periods 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.

Revenues. Retail propane revenue increased between comparable periods, 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.

Cost of Products Sold. Retail propane cost of products sold increased between comparable periods mainly due to the increase in gallons sold by customer service locations added through the Titan acquisition.

Gross Margin. The overall increase in gross margin between comparable periods 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. Our margin is influenced by market opportunities, independent competitors and concerns for long term retention of customers.

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Operating Expenses. The increase in operating expenses between comparable periods 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.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses between comparable periods 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 information technology 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.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense between comparable periods is due primarily to the acquisition of Titan on June 1, 2006.

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 December 31, 2008, and August 31, 2007 and 2006, and the four months ended December 31, 2007, our non-qualifying income 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.

We exceeded the 50% threshold on May 7, 2007, and, as a result, our partnership terminated for federal tax income purposes on that date. Our termination also caused ETP to terminate for federal income tax purposes on that date. These terminations did not affect our classification or the classification of ETP as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income or the qualifying income of ETP for federal income tax purposes. These terminations required both us and ETP to close our taxable years and to make new elections as to various tax matters. In addition, ETP was required to reset the depreciation schedule for its depreciable assets for federal income tax purposes. The resetting of ETP s depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to the Unitholders of ETP and, consequently, to our Unitholders. However, elections ETP and ETE made with respect to the amortization of certain intangible assets had the effect of reducing the amount of taxable income that would otherwise be allocated to ETE 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, ETP s wholly-owned subsidiary, HHI, which owns ETP s 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 ETP Common Units.

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The amount of such goodwill accumulated as of the date of ETP s 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. ETP accounts for HHI using the treasury stock method due to its ownership of ETP s Class E units. Due to the accounting rules outlined in SFAS 109 and related Interpretations, ETP accounts for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of ETP s HHI purchase price allocation, which effectively results in a charge to ETP s 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 December 31, 2008, 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 $3.4 million. As of December 31, 2008, the amount of tax goodwill to be amortized over the next 14 years for which HHI will receive a remedial income allocation is approximately $143.0 million.

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

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	1.59%	2.57%	1.25%	3.10%
Earnings not subject to tax at the Partnership level	(36.03)%	(32.41)%	(34.23)%	(32.80)%
Effective tax rate	0.56%	5.16%	2.02%	5.30%

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

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Current provision:				
Federal	$ (180)	$ 2,990	$ 7,896	$ 27,640
State	12,241	5,831	10,432	1,987
Total	12,061	8,821	18,328	29,627
Deferred provision:				
Federal	(8,531)	516	(7,494)	(6,227)
State	278	612	557	(385)
Total	(8,253)	1,128	(6,937)	(6,612)
Total Tax Provision	$ 3,808	$ 9,949	$ 11,391	$ 23,015

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. We recognized current state income tax expense related to the Texas margin tax of $10.5 million for the year ended December, 31, 2008, $3.9 million for the four months ended December 31, 2007 and $6.9 million for the year ended August 31, 2007. There is no comparable state tax expense for the year ended August 31, 2006.

Liquidity and Capital Resources

Parent Company Only

The Parent Company currently has no separate operating activities apart from those conducted by ETP and its Operating Partnerships. The principal sources of cash flow for the Parent Company are its direct and indirect investments in the limited and general partner

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interests of ETP. The amount of cash that ETP can distribute to its partners, including the Parent Company, each quarter is based on earnings from ETP s business activities and the amount of available cash, as discussed below. The Parent Company also has a $500.0 million revolving credit facility that expires in February 2011 with available capacity of $0.38 million as of December 31, 2008. The Parent Company is currently in discussions with ETP regarding the prospect of purchasing additional ETP Common Units as discussed below.

The Parent Company s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its general and limited partners. The Parent Company currently expects to fund its short-term needs for such items with its distributions from ETP.

In September 2007, ETE filed a registration statement on Form S-3 with the SEC to register the offer and sale of Common Units held by selling unitholders as well as $2.00 billion aggregate offering price of Common Units that may be offered and sold by ETE from time to time. This registration statement became effective in October 2007. ETE has not made any sales under this registration statement. ETE filed a Prospectus Supplement under SEC Rule 424(b)(3), dated January 24, 2008, to update information relating to the resale from time to time by the selling unitholders of up to 66,625,100 of ETE s Common Units.

ETP

ETP s ability to satisfy its obligations and pay distributions to its Unitholders will depend on its 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.

ETP currently believes that its business has the following future capital requirements:

- growth capital expenditures for our intrastate operations mainly for constructing new pipelines and compression for which we expect to spend between $390.0 million and $410.0 million during 2009;

- growth capital expenditures, excluding capital contributions to the MEP and FEP projects as discussed below, for the construction of new pipelines and pipeline expansions for our interstate operations, for which we expect to spend between $350.0 million and $375.0 million during 2009;

- capital contributions to MEP and FEP;

  - With respect to MEP, capital expenditures currently are being funded under a project financing arrangement, although the project facility is expected to reach its limit in early 2009, after which we will be required to make capital contributions to complete the project. We expect to make capital contributions to MEP of between $400.0 million and $420.0 million during 2009 to fund our portion of MEP s capital expenditures. In addition, we expect that we will need to make a capital contribution of approximately $260.0 million whenever MEP obtains permanent financing. MEP s existing credit facility is available until February 2011;

  - In October 2008, we announced the FEP project, as discussed in Note 3 of our consolidated financial statements. FEP intends to pursue separate financing for this project; however, the availability of such financing is uncertain. Excluding project financing, we expect that our capital contributions to FEP will be between $200.0 million and $220.0 million during 2009;

- growth capital expenditures for our propane operations of approximately $36.8 million during 2009;

- maintenance capital expenditures of approximately $130.0 million, which include (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; and (iii) capital expenditures for our propane operations to extend the useful lives of our existing propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet; and

any potential acquisition capital expenditures, including acquisition of new pipeline systems and propane operations.

ETP generally funds its capital expenditures with cash flows from operating activities and, to the extent that they exceed cash flows from operating activities, with proceeds of borrowings under existing credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof.

Although we have recently completed equity and debt offerings, current economic conditions make it difficult to obtain funding in either the debt or equity markets. The current constraints in the capital markets may affect our and ETP s ability to obtain funding through new borrowings or the issuance of Common Units. In addition, we and ETP expect that, to the extent we are successful in arranging new debt financing, we and ETP will incur increased costs associated with these debt financings. In light of the current market conditions, we and ETP have taken steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate for the fourth quarter of 2008 at the same level as the prior quarter and continuing to appropriately manage operating and administrative costs to improve profitability. ETP has also recently increased the available capacity under the ETP Credit Facility by using aggregate proceeds of approximately $821.9 million from ETP s December 2008 Senior Notes and January 2009 ETP Common Units offerings to repay outstanding borrowings. As of December 31, 2008, in addition to approximately $91.9 million of cash on hand, we had available capacity under the Parent Company s credit facilities and the ETP Credit Facility of $1.42 billion ($1.27 billion on a pro forma basis after giving effect to the $225.9 million of net proceeds from ETP s equity offering in January 2009). We expect to utilize these resources, along with cash from ETP s operations, to fund our announced growth capital expenditures for 2009 and working capital needs during 2009. In addition to these sources of liquidity, we may also access the debt and equity markets during 2009 in order to provide additional liquidity to fund growth capital expenditures for future years or for other partnership purposes.

ETP will continue to evaluate a variety of financing sources in order to fund its future growth capital expenditures and working capital needs, including funds available under our existing revolving credit facility, funds raised from future equity and/or debt offerings and funds raised from other sources, which sources may include project financing or other alternative financing arrangements from third parties or affiliated parties. In this regard, ETP has initiated discussions with us regarding the prospect of our purchasing additional ETP Common Units from ETP. We have an aggregate of approximately $378.4 million of cash on hand and available borrowing capacity under our revolving credit facility as of December 31, 2008.

ETP believes that the size and scope of its operations, its stable asset base and cash flow profile and its investment grade status will be significant positive factors in efforts to obtain new debt and equity funding; however, there is no assurance that we or ETP will be successful in obtaining financing under any of the alternatives discussed above if current capital market conditions continue for an extended period of time or if markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions, and other uncertainties.

The assets used in ETP s 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 ETP s existing assets. The assets utilized in ETP s propane operations do not typically require lengthy manufacturing process time or complicated, high technology components. Accordingly, ETP does not have any significant financial commitments for maintenance capital expenditures in its businesses. From time to time ETP experiences 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 its control. However, ETP includes these factors into its anticipated growth capital expenditures for each year.

ETP manages its 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 ETP will not be impacted by increased pipe costs and limited mill space.

ETP engages in natural gas storage transactions in which it seeks 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 ETP intends to fund natural gas purchases with cash generated from operations, from time to time it may need to finance the purchase of natural gas to be held in storage with borrowings from its current credit facilities. ETP intends to repay these borrowings with cash generated from operations when the gas is sold.

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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, and other factors.

Operating Activities. Cash provided by operating activities during the year ended December 31, 2008, was $823.8 million as compared to cash provided by operating activities of $754.5 million for the year ended August 31, 2007. The difference between net income and the net cash provided by operations for the year ended December 31, 2008 consisted of non-cash charges of $317.1 million (principally depreciation and amortization, minority interests and subsidiary distributions to minority unitholders) and changes in operating assets and liabilities of $131.6 million. Various components of operating assets and liabilities changed significantly from the prior period including factors such as the timing of accounts receivable collections, payments on accounts payable, the timing of the purchase and sale of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Investing Activities. Cash used in investing activities during the year ended December 31, 2008 of $2.02 billion was comprised primarily of cash paid for acquisitions of $84.8 million and $1.92 billion invested for growth capital expenditures (net of contribution in aid of construction costs as discussed in Note 2 to our consolidated financial statements), including changes in accruals of $57.9 million. Total growth capital expenditures consist of $1.19 billion for our intrastate operations, $695.1 million for our interstate operations, and $40.2 million for our propane operations. We also incurred $141.0 million in maintenance expenditures needed to sustain operations of which $75.4 million related to intrastate operations, $25.1 million related to interstate operations, and $40.5 million to propane operations. In addition, we received a reimbursement of $63.5 million, net during the first quarter of 2008 from MEP to the Partnership for previous advances to MEP. There were also advances of $9.0 million made to FEP during the year ended December 31, 2008.

Financing Activities. Cash provided by financing activities was $1.23 billion for the year ended December 31, 2008. We received $373.0 million in net proceeds from equity offerings of ETP (see Note 7 to our consolidated financial statements). Proceeds from the equity offerings were used to repay borrowings from the ETP Credit Facility. We also received net proceeds of approximately $2.08 billion from the issuance by ETP of new senior notes (see Note 6 to our consolidated financial statements) which were used to repay other indebtedness. During the year ended December 31, 2008, we had a net increase in our debt level of $1.32 billion primarily to fund our growth capital expenditures and for general partnership purposes. During the year ended December 31, 2008, we paid distributions of $435.9 million to our partners related to the four-month transition period ended December 31, 2007 and the quarters ended March 31, 2008, June 30, 2008, and September 30, 2008.

Financing and Sources of Liquidity

In January 2008, ETP issued 750,000 Common Units at $48.81 per Common Unit to underwriters pursuant to the exercise of a 30-day option to purchase additional Common Units to cover over-allotments in connection with its December 2007 public offering of 5,000,000 Common Units. The net proceeds from the option exercise of $35.0 million, were used to repay outstanding borrowings under the ETP Credit Facility (defined below).

In March 2008, ETP issued a total of $1.50 billion aggregate principal amount of ETP 2008 Senior Notes (defined below). The proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes were used to repay other indebtedness.

In July 2008, ETP issued 8,912,500 Common Units at $39.45 per Common Unit in a public offering. Net proceeds of approximately $338.0 million from the offering, including the capital contribution from ETP s general partner to maintain its 2% general partner s interest, were used to repay outstanding borrowings under the ETP Credit Facility.

On January 27, 2009, ETP issued 6,900,000 Common Units representing limited partner interests at $34.05 per Common Unit in a public offering. Net proceeds of approximately $225.9 million from the offering were used to repay outstanding borrowings under the ETP Credit Facility.

In December 2008, ETP issued a total of $600.0 million aggregate principal amount of 9.70% Senior Notes due 2019. The proceeds of approximately $595.7 million (net of bond discounts of $0.4 million and other offering costs of $3.9 million) from the issuance of the ETP 9.70% Senior Notes were used to repay indebtedness under the ETP Credit Facility, to pay expenses associated with the offering of the Notes, and for general partnership purposes.

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Description of Indebtedness

ETE s consolidated indebtedness as of December 31, 2008 includes the Parent Company s Senior Secured Credit Agreement which includes a $1.45 billion Senior Secured Term Loan Facility available through November 1, 2012 and a $500.0 million Senior Secured Revolving Credit Facility available through February 8, 2011. ETP has $4.05 billion aggregate principal amount of Senior Notes comprised of $600.0 million in principal amount of 9.70% Senior Notes due 2019, $350.0 million in principal amount of 6.00% Senior Notes due 2013, $600.0 million in principal amount of 6.70% Senior Notes due 2018, $550.0 million in principal amount of 7.50% Senior Notes due 2038, $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012, $400.0 million in principal amount of 6.125% Senior Notes due 2017 and $400.0 million in principal amount of 6.625% Senior Notes due 2036, each described below (collectively, the ETP Senior Notes), and the ETP Credit Facility, a revolving credit facility that allows for borrowings of up to $2.00 billion (expandable to $3.00 billion) available through July 20, 2012. ETP also has separate indebtedness at Transwestern and HOLP. The terms of our indebtedness and our subsidiaries are described in more detail below and in Note 6 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 subsidiaries ability to pay distributions. We are required to measure these financial tests and covenants quarterly and, as of December 31, 2008, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements. See Debt Covenants below.

Parent Company Indebtedness

The Parent Company has a $1.45 billion Term Loan Facility with a Term Loan Maturity Date of November 1, 2012 (the Parent Company Credit Agreement). The Parent Company Credit Agreement also includes a $500.0 million Secured Revolving Credit Facility (the Parent Company Revolving Credit Facility) available through February 8, 2011. The Parent Company Revolving Credit Facility includes a Swingline loan option with a maximum borrowing of $10.0 million and a daily rate based on LIBOR.

The total outstanding amount borrowed under the Parent Company Credit Agreement and the Parent Company Revolving Credit Facility as of December 31, 2008 was $1.57 billion. The total amount available under the Parent Company s debt facilities as of December 31, 2008 was $0.38 million. The Parent Company Revolving Credit Facility also contains an accordion feature which will allow the Parent Company, subject to lender approval, to expand the facility s capacity up to an additional $100.0 million.

The maximum commitment fee payable on the unused portion of the Parent Company Revolving Credit Facility is based on the applicable Leverage Ratio which is currently at Level III or 0.375%. Loans under the Parent Company Revolving Credit Facility bear interest at Parent Company s option at either (a) the Eurodollar rate plus the applicable margin or (b) base rate plus the applicable margin. The applicable margins are a function of the Parent Company s leverage ratio that corresponds to levels set-forth in the agreement. The applicable Term Loan bears interest at (a) the Eurodollar rate plus 1.75% per annum and (b) with respect to any Base Rate Loan, at Prime Rate plus 0.25% per annum. At December 31, 2008, the weighted average interest rate was 4.11% for the amounts outstanding on the Parent Company Senior Secured Revolving Credit Facility and the Parent Company $1.45 billion Senior Secured Term Loan Facility.

The Parent Company Credit Agreement is secured by a lien on all tangible and intangible assets of the Parent Company and its subsidiaries including its ownership of 62.5 million ETP Common Units, the Parent Company s 100% interest in ETP LLC and ETP GP with indirect recourse to ETP GP s 2% General Partner interest in ETP and 100% of ETP GP s outstanding incentive distribution rights in ETP, which the Parent Company holds through its ownership in ETP GP. The financial covenants contained in the revolving credit facility include a leverage ratio test, a consolidated leverage ratio test, an interest coverage ratio test and a value-to-loan ratio. Please see Note 6 to our consolidated financial statements included under Item 8 of this Form 10-K for further discussion of the covenants.

ETP Indebtedness

ETP 9.70% Senior Notes

In December 2008, ETP completed a public offering of $600.0 million aggregate principal amount of the ETP 9.70% Senior Notes due 2019 (the ETP 9.70% Senior Notes). The holders of the ETP 9.70% Senior Notes have the right to require us to repurchase all or a portion of the notes on March 15, 2012 at the principal amount plus any accrued interest as of that date. ETP used the proceeds of approximately $595.7 million, net of bond discounts and other offering costs, from the issuance of the ETP 9.70% Senior Notes to repay other indebtedess.

Interest on the ETP 9.70% Senior Notes is payable semiannually on March 15 and September 15 of each year. The Partnership may redeem some or all of the ETP 9.70% Senior Notes at any time, or from time to time, pursuant to the terms of the indenture.

ETP 2008 Senior Notes

In March 2008, ETP issued a total of $1.50 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the ETP 2008 Senior Notes). ETP used the proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes to repay borrowings and accrued interest outstanding under the $500.0 million, 364-day term loan credit facility (the ETP 364-Day Credit Facility) and to repay a portion of amounts outstanding under the ETP Credit Facility. Interest on the ETP 2008 Senior Notes is payable semiannually on January 1 and July 1 of each year. The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. The ETP 364-Day Credit Facility was a single draw term loan used for general corporate purposes, under which ETP borrowed the entire amount available under this facility on February 12, 2008, with an applicable Eurodollar rate plus 1.000% per annum based on the current rating by the rating agencies or at the Base Rate for a designated period. The indebtedness under the ETP 364-Day Credit Facility was unsecured and not guaranteed by us, ETP, or any of our or ETP s subsidiaries.

ETP 2006 Senior Notes

In October 2006, we issued a total of $400.0 million of 6.125% Senior Notes due 2017 and $400.0 million of 6.625% Senior Notes due 2036 (collectively, the ETP 2006 Senior Notes). Interest on the senior notes due 2017 is payable semi-annually on February 15 and August 15 of each year, beginning February 15, 2007, and interest on the senior notes due 2036 is payable semi-annually on April 15 and October 15 of each year, beginning April 15, 2007.

ETP 2005 Senior Notes

In July 2005, we issued a total of $400.0 million of 5.65% Senior Notes due 2012 (the ETP 5.65% Senior Notes). Interest on the ETP 5.65% Senior Notes is payable semi-annually on February 1 and August 1 of each year, beginning on February 1, 2006.

In January 2005, we issued a total of $750.0 million of 5.95% Senior Notes due 2015 (the ETP 5.95% Senior Notes, and collectively with the ETP 5.65% Senior Notes, the ETP 2005 Senior Notes). Interest on the ETP 5.95% Senior Notes is payable semi-annually on February 1 and August 1 of each year, beginning on August 1, 2005.

The ETP Senior Notes were issued under an indenture and related indenture supplements containing covenants, which, among other things, restrict ETP s ability to, subject to certain exceptions, incur debt secured by liens, engage in sale-leaseback transactions or merge or consolidate with another entity or sell substantially all of our assets. The ETP Senior Notes are unsecured obligations of ETP and the obligation of ETP to repay the ETP Senior Notes is not guaranteed by us, ETP, or any of our or ETP s subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ETP s or its 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 its existing and future subsidiaries.

Transwestern Senior Unsecured Notes

Transwestern s long-term debt consists of $213.0 million remaining principal amount of notes assumed in connection with the Transwestern acquisition and $307.0 million in principal amount of notes issued in May 2007, the proceeds from which were used to repay other indebtedness and for general corporate purposes. No principal payments are required under any of the Transwestern notes prior to their respective maturity dates. The Transwestern notes rank pari passu with Transwestern s other unsecured debt. The Transwestern 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 (collectively, the HOLP 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 December 31, 2008 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 Credit Facility

The ETP Credit Facility is a $2.00 billion revolving credit facility that is expandable to $3.00 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity) which 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). 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 includes a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2.00 billion unless expanded to $3.00 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%.

As of December 31, 2008, there was a balance outstanding on the ETP Credit Facility of $902.0 million in revolving credit loans with no outstanding balance in swingline loans, and approximately $60.0 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2008, was 2.82%. The total amount available under the ETP Credit Facility, as of December 31, 2008, which is reduced by any letters of credit, was approximately $1.04 billion ($1.27 billion on a pro forma basis after giving effect to the $225.9 million of net proceeds from our equity offering in January 2009). The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership s subsidiaries and has equal rights to holders of our other current and future unsecured debt. In connection with entering into the credit agreement for the ETP Credit Facility (July 2007), 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.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the HOLP Credit Facility) is available to HOLP through June 30, 2011 which may be expanded to $150.0 million. The HOLP Facility includes a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Credit 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 Credit Facility (total book value as of December 31, 2008 of approximately $1.3 billion). At December 31, 2008, there was $10.0 million outstanding on the revolving credit loans. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Credit Facility. There were outstanding letters of credit $1.0 million at December 31, 2008. The sum of the loans made under the HOLP Credit Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Credit Facility. The amount available as of December 31, 2008 was $64.0 million.

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MEP Guarantee

On February 29, 2008, MEP entered into a credit agreement that provides for a $1.40 billion senior revolving credit facility (the MEP Facility). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is available through February 28, 2011. Amounts borrowed under the MEP 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 MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets. The MEP Facility is syndicated among multiple financial institutions; the Royal Bank of Scotland PLC is the administrative agent. Among the lending banks that make up the syndicate of financial institutions for the MEP Facility, affiliates of Lehman Brothers had committed to approximately $100.0 million of the $1.40 billion facility. As a result of the Lehman Brothers bankruptcy in 2008, the MEP Facility has effectively been reduced by the amount of the Lehman Brothers affiliates commitment. However, the MEP Facility is not in default, and the commitments of the other lending banks remain unchanged.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP Facility for previous advances ETP made to MEP. As of December 31, 2008, MEP had $837.5 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $418.8 million and $16.7 million, respectively, as of December 31, 2008. The weighted average interest rate on the total amount outstanding as of December 31, 2008 was 3.1271%. The total amount available under the MEP Facility was $429.2 million as of December 31, 2008.

MEP previously had a $197.0 million reimbursement agreement under which MEP could issue letters of credit. This reimbursement agreement expired in and there are no longer any letters of credit outstanding.

Debt Covenants

The agreements related to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations in liens and a restriction on sale-leaseback transactions. The agreements related to each of the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to ETP and the Operating Partnerships, including the maintenance of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens as described in more detail below.

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 (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);

engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;

engage in transactions with affiliates;

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enter into restrictive agreements; and

enter into speculative hedging contracts.

The credit agreement related to the ETP Credit Facility also contains a financial covenant that provides that on each date ETP 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 defined in the ETP Credit Facility.

The agreements related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to HOLP, including the maintenance of various financial and leverage covenants and limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The financial covenants require HOLP to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not less than 2.25 to 1. These debt agreements also provide that HOLP 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 the amount of Available Cash (as defined in the agreements related to the HOLP Notes and HOLP Credit Facility) with respect to the immediately preceding quarter (which amount is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes during the last quarter 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 HOLP Notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates), (b) no default or event of default exists before such restricted payments, and (c) the amounts of HOLP s restricted payment is not disproportionately greater than the payment amount from ETC OLP utilized to fund payment obligations of ETP and its general partner with respect to ETP s Common Units.

Failure to comply with the various restrictive and affirmative covenants of our bank credit facilities and the note agreements related to the HOLP Notes 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 ETE s, ETP s, Transwestern s and HOLP s debt agreements as of December 31, 2008. ETP has previously announced various pipeline expansion projects for 2009, including the Katy expansion (expected to be in service by the end of the first quarter of 2009), the Phoenix project (completed in February 2009), the Midcontinent Express pipeline (first phase expected to be in service during the second quarter of 2009 and the second phase expected to be in service during the third quarter of 2009), and the Texas Independence pipeline (completion expected in the third quarter of 2009). ETP plans to fund its expansion capital expenditures, including the expansion projects expected to be completed in 2009 as well as other recently announced expansion projects, with cash flow from operations, proceeds from sales of its senior notes, borrowings under the ETP Credit Facility and/or proceeds from the sale of ETP Common Units. Please read Risk Factors Risks Related to Our Business Completion of pipeline expansion projects will require significant amounts of debt and equity financing which may not be available to ETP on acceptable terms, or at all. While we expect that financing for these expansion projects will result in an increase in our level of indebtedness in future quarters, we also expect that the incremental cash flow from the expansion projects expected to be completed in 2009 will allow ETP to satisfy the financial ratio covenants related to its existing debt during 2009.

Each of the agreements referred to above are incorporated herein by reference to ETP s reports previously filed with the SEC under the Exchange Act. See Item 1, Business SEC Reporting.

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Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2008 (in thousands):

		Payments Due by Period			
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 7,235,589	$ 45,232	$ 206,862	$ 3,147,308	$ 3,836,187
Interest on fixed rate long-term debt (a)	4,097,248	307,958	637,148	604,179	2,547,963
Payments on derivatives	264,142	142,432	88,558	23,684	9,468
Purchase commitments (b)	259,483	256,901	2,582		
Operating lease obligations	314,648	21,041	38,498	30,999	224,110
Totals	$ 12,171,110	$ 773,564	$ 973,648	$ 3,806,170	$ 6,617,728

(a) See Liquidity and Capital Resources Revolving Credit and Short-Term Debt Facilities MEP Guarantee.

(b) 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 December 31, 2008, variable rate interest on our outstanding balance of variable rate debt of $2.48 billion would be $90.3 million on an annual basis. See Note 6 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.

(c) 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 December 31, 2008 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.

Cash Distributions

Cash Distributions Paid by the Parent Company

Under the Parent Company Partnership Agreement, the Parent Company will distribute all of its Available Cash, as defined, within 50 days following the end of each fiscal quarter. Available cash generally means, with respect to any 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 that is necessary or appropriate to provide for future cash requirements.

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Distributions declared since the Parent Company s Initial Public Offering in February 2006 are as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2008	November 10, 2008	November 19, 2008	$ 0.4800
	August 7, 2008	August 19, 2008	0.4800
	May 5, 2008	May 19, 2008	0.4400
	February 1, 2008 (1)	February 19, 2008	0.5500
Transition Period Ended December 31, 2007	October 5, 2007	October 19, 2007	$ 0.3900
Fiscal Year Ended August 31, 2007	July 2, 2007	July 19, 2007	$ 0.3725
	April 9, 2007	April 16, 2007	0.3560
	January 4, 2007	January 19, 2007	0.3400
	October 5, 2006	October 19, 2006	0.3125
Fiscal Year Ended August 31, 2006	June 30, 2006	July 19, 2006	$ 0.2375
	March 31, 2006	April 19, 2006	0.0578

On January 26, 2009, Parent Company announced the declaration of a cash distribution for the fourth quarter ended December 31, 2008 of $0.51 per Common Unit, or $2.04 annually, an increase of $0.12 per Common Unit on an annualized basis. We paid this distribution on February 19, 2009 to Unitholders of record at the close of business on February 6, 2009.

The total amount of distributions (all from Available Cash from the Parent Company s operating surplus) declared during the periods ended as noted below are as follows (in thousands):

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Limited Partners -				
Limited Partners	$	$	$	$ 34,010
Common Units	434,519	86,904	246,136	65,905
Class B Units			1,645	745
Class C Units			28,261	
General Partner	1,349	270	955	599
Total distributions declared	$ 435,868	$ 87,174	$ 276,997	$ 101,259

Cash Distributions Received by the Parent Company

Currently, the Parent Company s only cash-generating assets are its direct and indirect partnership interests in ETP. These ETP interests consist of all of ETP s 2% general partner interest, 100% of ETP s incentive distribution rights and ETP Common Units held by the Parent Company.

The total amount of distributions the Parent Company received from ETP relating to its limited partner interests, general partner interest and Incentive Distribution Rights for the periods ended as noted below is as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Limited Partners Interests	$ 236,331	$ 51,563	$ 174,969	$ 80,203
General Partner Interest	17,851	3,553	12,701	6,931

Incentive Distribution Rights	305,072	59,315	183,056	64,436
Less holdback (a)	(13,098)			(2,287)
Total distributions received from ETP	$ 546,156	$ 114,431	$ 370,726	$ 149,283

(a) Represents amounts held back for reimbursement of expenses and contributions required to maintain ETP GP s 2% General Partner interest in ETP.

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Cash Distributions Paid by ETP

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

Distributions declared by ETP are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2008	November 10, 2008	November 14, 2008	$ 0.89375
	August 7, 2008	August 14, 2008	0.89375
	May 5, 2008	May 15, 2008	0.86875
	February 1, 2008 (1)	February 14, 2008	1.12500
Transition Period Ended December 31, 2007	October 5, 2007	October 15, 2007	$ 0.82500
Fiscal Year Ended August 31, 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 Ended August 31, 2006	June 30, 2006	July 14, 2006	$ 0.63750
	June 30, 2006 (2)	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

(1) One-time four month distribution On January 18, 2008 the Board of Directors of ETP s General Partner approved the management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP s distribution amount related to the four months ended December 31, 2007 was $1.125 per Common Unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This distribution was paid on February 14, 2008 to ETP s Unitholders of record as of the close of business on February 1, 2008.

(2) Special SCANA distribution On June 20, 2006, the Board of Directors of ETP s 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 ETP s 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 the Board of Directors of ETP s General Partner to distribute all the net distributable litigation proceeds we received in accordance with the partnership agreement. The special distribution also included a payment distribution of $3.6 million to the holder of ETP s Class C Units for that amount that would otherwise have been distributed to its General Partner.

On January 26, 2009, ETP announced the declaration of a cash distribution for the fourth quarter ended December 31, 2008 of $0.89375 per Common Unit, or $3.575 annually. ETP paid this distribution on February 13, 2009 to Unitholders of record at the close of business on February 6, 2009.

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The total amount of distributions (all from Available Cash from ETP s operating surplus) declared during the periods ended as noted below are as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Limited Partners -				
Common Units	$ 556,295	$ 113,080	$ 366,180	$ 248,237
Class C Units (1)				3,599
Class E Units	12,484	3,121	12,484	12,484
Class F Units				3,232
Class G Units			40,598	
General Partners -				
2% Ownership	17,851	3,582	12,701	6,981
Incentive Distribution Rights	305,072	59,315	203,069	81,722
	$ 891,702	$ 179,098	$ 635,032	$ 356,255

(1) Special SCANA distribution see discussion above.

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.

New Accounting Standards

See Note 2 to our consolidated financial statements.

Estimates and Critical Accounting Policies

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 2 to our consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and accruals for and disclosure 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 intrastate 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 year ended December 31, 2008 represent the actual results in all material respects.

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 compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

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 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 marketing operations 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 12 to our consolidated financial statements, 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 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 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 marketing operations, 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.

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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 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 Statement of Financial Accounting Standards 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 intrastate 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 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.

Financial Assets and Liabilities at Fair Value. We adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, (SFAS 157) effective January 1, 2008. SFAS 157 provides a definition of fair value, establishes a fair value framework and hierarchy under GAAP and provides for expanded disclosures of fair value measurements. SFAS 157 does not require any new fair value measurements other than those established by other GAAP requirements. As noted under New Accounting Standards (see Note 2 of our consolidated financial statements), the effective date of SFAS 157 has been deferred with respect to certain non-financial assets and liabilities.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. In accordance with SFAS 157, we determine the fair value of our financial assets and liabilities subject to fair value measurement by using the highest possible Level as defined in SFAS 157. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (OTC) commodity derivatives entered into directly with third parties Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. Level 3 utilizes significant unobservable inputs. We currently do not have any fair value measurements within the scope of SFAS 157 that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations as defined by SFAS 157. See further information on our fair value assets and liabilities in Note 2 of our consolidated financial statements.

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 indefinite 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 the consolidated statement of operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful lives 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 lives of our property, plant, and equipment.

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 we can reasonably determine the settlement dates.

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

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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 11 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 ETP s pipelines and gathering systems;
- the level of throughput in ETP s natural gas processing and treating facilities;
- the fees ETP charges and the margins it realizes for its 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;

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- 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 ETP s pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of ETP s liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by ETP s 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 ETP s existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third party contractors;
- the availability and cost of capital and ETP s ability to access certain capital sources;
- the further deterioration of the credit and capital markets;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to ETP s 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 risks 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, NGLs and propane 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, President and Chief Operating Officer, Vice President of Administration, Senior Vice President of marketing, and Controller of our midstream and intrastate 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 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 at the current market prices during periods of low demand, which generally occur during the summer months. The propane is then stored at both our customer service locations and in major storage facilities for future resale.

Non-trading Activities

We use a combination of derivative 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 derivative 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 these transactions.

We manage our price risk related to future physical purchase or sale commitments for our marketing 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. As of December 31, 2008, these contracts have settled and are no longer reflected on our consolidated balance sheet.

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. 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 (AOCI) until the underlying hedged transaction is recorded in earnings. 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 is recorded in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transactions are recorded in earnings, 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 each period in cost of products sold in the consolidated statements of operations.

We 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

Due to a high level of market volatility as well as other business considerations, as of July 2008 we determined that we will no longer engage in the trading of financial derivative instruments that are not offset by physical positions. As a result, we will no longer have any material exposure to market risk from such derivative positions. The derivative contracts that were previously entered into for trading purposes are recognized in the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized each period in midstream and intrastate transportation and storage revenue in the consolidated statements of operations on a net basis.

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Commodity-related Derivatives

Our commodity-related price risk management assets and liabilities as of December 31, 2008 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability) (in thousands)
Mark to Market Derivatives				
Basis Swaps IFERC/NYMEX	Gas	15,720,000	2009 - 2011	$ 3,125
Swing Swaps IFERC	Gas	(58,045,000)	2009	(118)
Fixed Swaps/Futures	Gas	(20,880,000)	2009 - 2010	97,498
Forward/Swaps - in Gallons	Propane	47,313,002	2009	(42,288)
Cash Flow Hedging Derivatives				
Basis Swaps IFERC/NYMEX	Gas	(9,085,000)	2009	3,268
Fixed Swaps/Futures	Gas	(9,085,000)	2009	6,691

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 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.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

Sensitivity Analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of December 31, 2008. 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 (in thousands)
Basis Swaps IFERC/NYMEX	6,635,000	$ 6,393	$ 28
Swing Swaps IFERC	(58,045,000)	(118)	1
Fixed Swaps/Futures	(29,965,000)	104,189	17,401
Propane Forwards/Swaps (in Gallons)	47,313,002	(42,288)	3,074

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% 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 AOCI. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instruments settle, and the location to which the financial instruments are tied (i.e., basis swaps), and the relationship between prompt month and forward months.

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Interest Rate Risk

We are exposed to market risk for changes 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 December 31, 2008, we had a total of $2.48 billion of variable rate debt outstanding and we have $2.13 billion of interest rate swaps where we pay fixed and receive floating LIBOR. Interest swaps with a notional amount of $700.0 million are designated as hedges and changes in fair value are recorded in accumulated other comprehensive income. Interest swaps with a notional amount of $1.40 billion have their changes in fair value recorded in other income on the consolidated statement of operations. The last leg of this swap has been fixed and it is no longer subject to volatility. Additionally, the Partnership entered into forward starting swaps in December 2008 with a notional amount of $500.0 million. A hypothetical change of 100 basis points in the underlying interest rate and a corresponding parallel shift in the LIBOR yield curve would have an effect of $59.8 million in interest expense and other income, in the aggregate, on an annual basis.

We also have long-term debt instruments which are typically issued at fixed interest rates. Prior to or when these debt obligations mature, 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 12 to our consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Equity, L.P. and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Equity, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Equity, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for the year ended December 31, 2008, for the four months ended December 31, 2007, and for each of the two 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 Equity, L.P. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for the year ended December 31, 2008, for the four months ended December 31, 2007, and for each of the two 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), Energy Transfer Equity, L.P. s internal control over financial reporting as of December 31, 2008, 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 February 27, 2009 expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Dallas, Texas

February 27, 2009

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands, except unit data)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 92,023	$ 56,557
Marketable securities	5,915	3,002
Accounts receivable, net of allowance for doubtful accounts	591,257	822,027
Accounts receivable from related companies	15,142	18,070
Inventories	272,348	361,954
Deposits paid to vendors	78,237	42,273
Exchanges receivable	45,209	37,321
Price risk management assets	5,423	8,203
Prepaid expenses and other	75,441	54,389
Total current assets	1,180,995	1,403,796
PROPERTY, PLANT AND EQUIPMENT, net	8,702,534	6,852,458
ADVANCES TO AND INVESTMENT IN AFFILIATES	10,110	86,167
GOODWILL	773,283	757,698
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	402,980	361,975
Total assets	$ 11,069,902	$ 9,462,094

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

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands, except unit data)

	December 31, 2008	December 31, 2007
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable	$ 381,933	$ 673,116
Accounts payable to related companies	34,495	48,012
Exchanges payable	54,636	40,382
Customer advances and deposits	106,679	75,831
Accrued wages and benefits	65,754	35,729
Accrued capital expenditures	153,230	87,622
Accrued and other current liabilities	94,156	133,500
Price risk management liabilities	142,432	13,547
Interest payable	115,487	78,933
Income taxes payable	14,298	7,264
Deferred income taxes	589	429
Current maturities of long-term debt	45,232	47,068
Total current liabilities	1,208,921	1,241,433
LONG-TERM DEBT, less current maturities	7,190,357	5,870,106
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	121,710	46,479
DEFERRED INCOME TAXES	194,871	199,934
OTHER NON-CURRENT LIABILITIES	14,727	12,986
MINORITY INTERESTS	2,422,748	2,106,819
COMMITMENTS AND CONTINGENCIES (Note 10)		
	11,153,334	9,477,757
PARTNERS CAPITAL (DEFICIT):		
General Partner	155	192
Limited Partners:		
Common Unitholders (222,829,956 units authorized, issued and outstanding at December 31, 2008 and 2007)	(15,762)	(4,628)
Accumulated other comprehensive loss	(67,825)	(11,227)
Total partners deficit	(83,432)	(15,663)
Total liabilities and partners deficit	$ 11,069,902	$ 9,462,094

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

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit and unit data)

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
REVENUES:				
Natural gas operations	$ 7,653,156	$ 1,832,192	$ 5,385,892	$ 6,877,512
Retail propane	1,514,599	471,494	1,179,073	799,358
Other	125,612	45,656	227,072	182,226
Total revenues	9,293,367	2,349,342	6,792,037	7,859,096
COSTS AND EXPENSES:				
Cost of products sold, natural gas operations	5,885,982	1,343,237	4,207,700	5,963,422
Cost of products sold, retail propane	1,014,068	315,698	734,204	493,642
Cost of products sold, other	38,030	14,719	136,302	111,252
Operating expenses	781,831	221,757	559,600	422,989
Depreciation and amortization	274,372	75,406	191,383	129,636
Selling, general and administrative	200,181	61,874	153,512	162,615
Total costs and expenses	8,194,464	2,032,691	5,982,701	7,283,556
OPERATING INCOME	1,098,903	316,651	809,336	575,540
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(357,541)	(103,375)	(279,986)	(150,646)
Loss on extinguishment of debt				(5,060)
Equity in earnings (losses) of affiliates	(165)	(94)	5,161	(479)
Gain (loss) on disposal of assets	(1,303)	14,310	(6,310)	851
Gains (losses) on non-hedged interest rate derivatives	(128,423)	(28,683)	29,081	
Allowance for equity funds used during construction	63,976	7,276	4,948	
Other, net	8,115	(13,327)	1,129	13,701
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	683,562	192,758	563,359	433,907
Income tax expense	3,808	9,949	11,391	23,015
INCOME BEFORE MINORITY INTERESTS	679,754	182,809	551,968	410,892
Minority interests	(304,710)	(90,132)	(232,608)	(303,752)
NET INCOME	375,044	92,677	319,360	107,140
GENERAL PARTNER'S INTEREST IN NET INCOME	1,161	287	1,048	609
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 373,883	$ 92,390	$ 318,312	$ 106,531

BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.68	$ 0.41	$ 1.56	$ 0.80
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	222,829,956	222,829,916	204,578,719	133,820,176
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.68	$ 0.41	$ 1.55	$ 0.79
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	222,829,956	222,829,916	204,578,719	133,820,176

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

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Net income	$ 375,044	$ 92,677	$ 319,360	$ 107,140
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	(22,916)	(17,970)	(163,378)	(74,507)
Change in value of derivative instruments accounted for as cash flow hedges	(40,350)	(2,221)	179,861	167,525
Change in value of available-for-sale securities	(6,418)	(98)	280	(634)
Minority interests	13,086	(2,700)	(7,277)	(63,415)
	(56,598)	(22,989)	9,486	28,969
Comprehensive income	$ 318,446	$ 69,688	$ 328,846	$ 136,109

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

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL (DEFICIT)

(Dollars in thousands)

	General Partner	Common Unitholders	Class B Unitholders	Class C Unitholders	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Total
Balance, August 31, 2005	$ 772	$	$	$	$ (62,216)	$ (26,693)	$ (88,137)
Units issued in IPO, net of issuance costs		473,978					473,978
Distribution of interest in ETP GP, LP	(27)	(4,428)					(4,455)
Conversion to Common Units		(39,606)			39,606		
Redemption of Common Units	(824)	(130,796)					(131,620)
Repurchase of Common Units		(237,817)					(237,817)
Distributions to partners	(599)	(65,905)	(745)		(34,010)		(101,259)
Purchase premium on ETP shares		(54,001)					(54,001)
Compensation expense on issuance of Class B Units			52,953				52,953
Other comprehensive income, net of tax						28,969	28,969
Net income	609	48,989	922		56,620		107,140
Balance, August 31, 2006	(69)	(9,586)	53,130			2,276	45,751
Unit issuances (Note 2)		372,638		4,456			377,094
Equity issue costs of Class C Units				(204)			(204)
Assumption of related company debt (Note 7)				(70,500)			(70,500)
Distribution to partners	(955)	(246,136)	(1,645)	(28,261)			(276,997)
Purchase premium on ETP Class G Units (Note 7)		(451,150)					(451,150)
Non-cash unit-based compensation expense		28					28
Other comprehensive income, net of tax						9,486	9,486
Net income	1,048	260,184	2,524	55,604			319,360
Conversion to Common Units		15,104	(54,009)	38,905			
Balance, August 31, 2007	24	(58,918)				11,762	(47,132)
Distributions to partners	(270)	(86,904)					(87,174)
Non-cash unit-based compensation expense		23					23
Subsidiary sale of common units	151	48,781					48,932
Other comprehensive loss, net of tax						(22,989)	(22,989)
Net income	287	92,390					92,677
Balance, December 31, 2007	192	(4,628)				(11,227)	(15,663)
Distributions to partners	(1,349)	(434,519)					(435,868)
Non-cash unit-based compensation expense		823					823
Non-cash executive compensation		48					48
Subsidiary sale of common units	151	48,631					48,782
Other comprehensive loss, net of tax						(56,598)	(56,598)
Net income	1,161	373,883					375,044

Balance, December 31, 2008	$	155	$	(15,762)	$		$		$		$	(67,825)	$	(83,432)

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

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	375,044	$ 92,677	$ 319,360	$ 107,140
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	274,372	75,406	191,383	129,636
Amortization in interest expense	10,962	2,441	6,691	3,959
Loss on extinguishment of debt				5,060
Provision for loss on accounts receivable	8,015	544	4,229	1,723
(Gain) loss on disposal of assets	1,303	(14,310)	6,310	(851)
Goodwill impairment	11,359			
Non-cash unit-based compensation expense	24,304	8,137	10,499	59,991
Non-cash executive compensation	1,250	442		
Distribution in excess of earnings (losses) of affiliates, net	5,621	4,448	(5,161)	(378)
Deferred income taxes	(8,177)	37	(6,939)	(6,724)
Minority interests and other non-cash	308,092	88,063	231,848	303,752
Subsidiary distributions to minority unitholders	(319,963)	(61,517)	(251,823)	(192,146)
Net change in operating assets and liabilities, net of acquisitions	131,575	(49,250)	248,100	(100,380)
Net cash provided by operating activities	$ 823,757	$ 147,118	$ 754,497	$ 310,782
CASH FLOWS FROM INVESTING ACTIVITIES:				
Cash paid for acquisitions, net of cash acquired	(84,783)	(337,092)	(90,695)	(586,185)
Working capital settlement on prior year acquisitions				19,653
Capital expenditures	(2,054,806)	(651,228)	(1,107,127)	(687,492)
Contributions in aid of construction costs	50,050	3,493	10,463	7,328
Advances to and investment in affiliates	54,534	(32,594)	(993,866)	(4,651)
Proceeds from the sale of assets	19,420	21,478	23,135	6,941
Net cash used in investing activities	(2,015,585)	(995,943)	(2,158,090)	(1,244,406)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	6,205,994	1,742,802	6,010,633	3,495,806
Principal payments on debt	(4,890,619)	(1,062,272)	(4,628,052)	(2,567,053)
Equity offerings			372,434	473,978
Redemption of Common Units				(131,620)
Repurchase of Common Units				(237,817)
Equity offering of subsidiary	373,059	234,887		
Distributions to Partners	(435,868)	(87,174)	(276,997)	(101,259)
Debt issuance costs	(25,272)	(211)	(23,279)	(5,666)
Net cash provided by financing activities	1,227,294	828,032	1,454,739	926,369

INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		35,466		(20,793)		51,146		(7,255)
CASH AND CASH EQUIVALENTS, beginning of period	$	56,557		77,350		26,204		33,459
CASH AND CASH EQUIVALENTS, end of period	$	92,023	$	56,557	$	77,350	$	26,204

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

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular dollar amounts in thousands, except per unit data)

1. OPERATIONS AND ORGANIZATION:

Financial Statement Presentation

The consolidated financial statements of Energy Transfer Equity, L.P. and subsidiaries (the Partnership , ETE or the Parent Company) presented herein for the year ended December 31, 2008, the four months ended December 31, 2007 and the years ended August 31, 2007 and 2006, 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 (SEC). We consolidate all majority-owned subsidiaries and limited partnerships which we control as the general partner or owner of the general partner. We present 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 include the results of operations for ETE, ETE s controlled subsidiary Energy Transfer Partners, L.P., a publicly-traded master limited partnership (ETP), and ETE s wholly-owned subsidiaries: Energy Transfer Partners GP, L.P. (ETP GP), the General Partner of ETP, and Energy Transfer Partners, L.L.C. (ETP LLC), the General Partner of ETP GP. The results of operations for ETP include its wholly-owned subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP); Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, LLC (ETC MEP); Heritage Operating, L.P. (HOLP); Heritage Holdings, Inc. (HHI); and Titan Energy Partners, L.P. (Titan). The operations of Titan are included since the date of acquisition on June 1, 2006, and the operations of ET Interstate are included since the date of the Transwestern acquisition on December 1, 2006. The operations of all other subsidiaries listed above are reflected for all periods presented.

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.

In November 2007, we filed a Form 8-K indicating that our Limited Partnership Agreement had been amended to change our fiscal year end to the calendar year. Thus, a new fiscal year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the year ended December 31, 2008, the four months ended December 31, 2007, and the years ended August 31, 2007 and 2006.

We did not recast the financial data for the prior fiscal period because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the year ended December 31, 2008 are substantially similar to what is reflected in the information for the year ended August 31, 2007.

Certain prior period amounts have been reclassified to conform with the 2008 presentation. These reclassifications had no impact on net income or total partners capital.

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Business Operations

The Parent Company currently has no separate operating activities apart from those conducted by the Operating Partnerships. The Parent Company s principal sources of cash flow are its direct and indirect investments in the Limited Partner and General Partner interests in ETP.

The Parent Company s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The Parent Company-only assets and liabilities of ETE are not available to satisfy the debts and other obligations of ETP and its consolidated subsidiaries. In order to fully understand the financial condition of the Partnership on a stand-alone basis, see Note 17 for stand-alone financial information apart from that of the consolidated partnership information included herein.

In order to simplify the obligations of the Partnership under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through five 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, all of which are Delaware limited liability companies engaged in interstate transportation of natural gas;
- ETC Fayetteville Express Pipeline, LLC (ETC FEP), a Delaware limited liability company 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 , ETE , ETP , Energy Transfer or the Partnership. References to the Parent Company shall mean Energy Transfer Equity, L.P. on a stand-alone basis.

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, Arizona, New Mexico, Utah and Colorado.

ETC OLP owns an interest in and operates approximately 14,600 miles of in service natural gas gathering and intrastate transportation pipelines with an additional 250 miles of intrastate pipeline under construction, three natural gas processing plants, eleven natural gas treating facilities, eleven natural gas conditioning facilities and three natural gas storage facilities located in Texas.

The midstream operations focus on the gathering, compression, treating, blending, and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah. 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 principally 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 focus on natural gas transportation of Transwestern, which owns and operates approximately 2,700 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. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues, costs 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 intrastate 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 year ended December 31, 2008 represent the actual results in all material respects.

Some of the other 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, fair value measurements used in goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

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 rental income 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

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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 marketing operations 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.

As further discussed in Note 12, in July 2008 we determined that we will no longer engage in the trading of financial derivatives that are not offset by physical positions. Prior to that, we had a risk management policy that provided for our marketing and trading operations to execute limited strategies. Those activities were 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 included purchasing and selling natural gas and the use of financial instruments, including basis contracts and gas daily contracts. We accounted for our trading activities under the provisions of Emerging Issues Task Force 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.

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 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 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 marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers working natural gas in our storage facilities. We also 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. 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. We expect margins from natural gas storage transactions 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

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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.

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, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation (FDIC) insurance limit.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Accounts receivable	$ 220,635	$ (169,263)	$ 54,347	$ 189,719
Accounts receivable from related companies	3,234	(12,091)	(5,376)	1,828
Inventories	96,145	(168,430)	196,173	(83,448)
Deposits paid to vendors	(35,964)	3,243	42,316	(22,772)
Exchanges receivable	(7,888)	(4,216)	(3,406)	12,402
Prepaid expenses and other	(21,186)	(7,702)	11,275	(27,128)
Regulatory assets	(24,588)	(1,918)	663	-
Intangibles and other long-term assets	(16,165)	2,523	(2,480)	(2,687)
Accounts payable	(296,185)	195,574	(92,296)	(295,173)
Accounts payable to related companies	(13,538)	28,876	18,560	(135)
Exchanges payable	14,254	6,117	3,000	(9,050)
Customer advances and deposits	29,751	(6,775)	(27,962)	(41,179)
Accrued wages and benefits	26,513	(17,214)	13,258	16,525
Accrued and other current liabilities	(30,824)	24,238	(14,884)	53,450
Interest payable	36,501	41,640	18,181	2,650
Income taxes payable	7,034	777	2,794	(2,103)
Other long-term liabilities	1,741	(680)	1,460	(13,179)
Price risk management liabilities, net	142,105	36,051	32,477	119,900
Net change in assets and liabilities, net of effect of acquisitions	$ 131,575	$ (49,250)	$ 248,100	$ (100,380)

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Non-cash investing and financing activities and supplemental cash flow information is as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
NON-CASH INVESTING ACTIVITIES:				
Transfer of investment in affiliate in purchase of Transwestern (Note 3)	$	$	$ 956,348	$
Investment in Calpine Corporation received in exchange for accounts receivable	$ 10,816	$	$	$
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 5,077	$ 3,896	$ 533,625	$ 4,234
Subsidiary issuance of Common Units in connection with certain acquisitions	$ 2,228	$ 1,400	$	$ 4,000
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$ 330,816	$ 79,084	$ 283,854	$ 159,541
Cash paid for income taxes	$ 5,191	$ 9,135	$ 8,962	$ 38,138

Marketable Securities

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

During the year ended December 31, 2008, we determined there was an other-than-temporary decline in the market value of one of our available-for-sale securities, and reclassified into earnings a loss of $1.4 million, which is recorded in other expense. Unrealized holding gains (losses), net of tax, of $(6.4) million, $(0.1) million, $0.3 million, and $(0.6) million were recorded through accumulated other comprehensive income (AOCI), based on the market value of the securities, for the fiscal year ended December 31, 2008, the four months ended December 31, 2007, and the fiscal years ended August 31, 2007 and 2006, respectively.

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 intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. 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 2008 and 2007; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage segments was not deemed necessary.

ETP s interstate transportation operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our 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. Transwestern sought additional assurances from customers due to credit concerns, and held aggregate prepayments of $0.8 million and $0.6 million at December 31, 2008 and 2007, respectively, 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.

ETP s propane operations 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 propane segment is based on management s assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

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.

We exchanged a portion of our outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation (Calpine) common stock during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock is included in marketable securities on the consolidated balance sheet as of December 31, 2008 at a fair value of $4.8 million.

Accounts receivable consisted of the following:

	December 31, 2008	December 31, 2007
Midstream and intrastate transportation and storage	$ 415,507	$ 612,533
Interstate transportation	29,309	31,676
Propane	155,191	183,516
Less allowance for doubtful accounts	(8,750)	(5,698)
Total, net	$ 591,257	$ 822,027

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

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Balance, beginning of the period	$ 5,698	$ 5,601	$ 4,000	$ 4,076
Accounts receivable written off, net of recoveries	(4,963)	(447)	(2,628)	(1,799)
Provision for loss on accounts receivable	8,015	544	4,229	1,723
Balance, end of period	$ 8,750	$ 5,698	$ 5,601	$ 4,000

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.

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Inventories consisted of the following:

	December 31, 2008	December 31, 2007
Natural gas and NGLs, excluding propane	$ 184,727	$ 268,148
Propane	63,967	74,309
Appliances, parts and fittings and other	23,654	19,497
Total inventories	$ 272,348	$ 361,954

During the three months ended December 31, 2008, we recorded lower-of-cost-or-market adjustments of $69.5 million for natural gas inventory and $4.4 million for propane inventory to reflect market values which were less than the weighted-average cost. The natural gas inventory adjustment was partially offset in net income by the recognition of unrealized gains on related cash flow hedges in the amount of $21.7 million from AOCI. No lower-of-cost-or-market adjustments were recorded for the other periods presented.

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.

The interstate transportation 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 useful 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.

Capitalized interest is included for pipeline construction projects, except for interstate projects for which an allowance for funds used during construction (AFUDC) is accrued. Interest is capitalized based on the current borrowing rate of ETP s revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts borrowed funds and equity funds.

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

	December 31, 2008	December 31, 2007
Land and improvements	$ 74,895	$ 65,348
Buildings and improvements (10 to 30 years)	133,951	118,438
Pipelines and equipment (10 to 80 years)	5,592,057	4,113,026
Natural gas storage (40 years)	92,457	91,656
Bulk storage, equipment and facilities (3 to 30 years)	496,462	463,807
Tanks and other equipment (5 to 30 years)	578,118	528,777
Vehicles (5 to 10 years)	193,645	161,920
Right of way (20 to 80 years)	366,205	271,412
Furniture and fixtures (3 to 10 years)	28,075	24,928
Linepack	48,108	41,099
Pad gas	53,583	53,242
Other (5 to 10 years)	97,975	86,602
	7,755,531	6,020,255
Less Accumulated depreciation	(762,014)	(514,169)
	6,993,517	5,506,086
Plus Construction work-in-process	1,709,017	1,346,372
Property, plant and equipment, net	$ 8,702,534	$ 6,852,458

We recognized the following amounts of depreciation expense, capitalized interest, and AFUDC for the periods presented:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Depreciation expense	$ 256,910	$ 68,642	$ 175,851	$ 119,369
Capitalized interest, excluding AFUDC	$ 21,595	$ 12,657	$ 22,979	$ 12,605
AFUDC	$ 50,074	$ 5,095	$ 3,600	$

Asset Retirement Obligation

We 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, we also 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.

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 was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2008 or 2007 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 influence over, but do not control, the investee s operating and financial policies.

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We account for our investments in Midcontinent Express Pipeline, LLC and Fayetteville Express Pipeline LLC using the equity method. See Note 3 for a discussion of these joint ventures.

Goodwill

Goodwill is associated with acquisitions made for our midstream, intrastate transportation and storage, interstate transportation, and retail propane segments. Substantially all of the $773.3 million balance in goodwill is expected to be tax deductible. Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of December 31 for subsidiaries in our interstate segment and as of August 31 for all others. During the three months ended December 31, 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No other goodwill impairments were recorded for the periods presented in these consolidated financial statements. Changes in the carrying amount of goodwill were as follows:

	Midstream	Intrastate Transportation and Storage	Interstate Transportation	Retail Propane	Other	Total
Balance as of August 31, 2007	$ 13,409	$ 10,327	$ 107,550	$ 587,143	$ 29,589	$ 748,018
Purchase accounting adjustments			(8,937)	190		(8,747)
Goodwill acquired	10,959			7,742		18,701
Sale of operations				(274)		(274)
Balance as of December 31, 2007	24,368	10,327	98,613	594,801	29,589	757,698
Purchase accounting adjustments				2,457		2,457
Goodwill acquired	9,141			15,346		24,487
Goodwill impairment	(11,359)					(11,359)
Balance as of December 31, 2008	$ 22,150	$ 10,327	$ 98,613	$ 612,604	$ 29,589	$ 773,283

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation. This preliminary goodwill balance may be adjusted when the purchase price allocation is finalized. As of December 31, 2008, purchase price allocations have been finalized for all significant acquisitions (see Note 3).

Intangibles and Other Long-Term 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:

	December 31, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 40,301	$ (24,374)	$ 34,855	$ (19,438)
Customer lists (3 to 15 years)	144,337	(39,730)	139,097	(26,821)
Contract rights (6 to 15 years)	23,015	(3,744)	23,015	(1,849)
Other (10 years)	2,677	(2,244)	2,677	(1,463)
Total amortizable intangible assets	210,330	(70,092)	199,644	(49,571)
Non-amortizable intangible assets - Trademarks	75,667		70,339	
Total intangible assets	285,997	(70,092)	269,983	(49,571)

Other long-term assets:				
Financing costs (3 to 15 years)	74,611	(23,508)	57,934	(14,493)
Regulatory assets	98,560	(5,941)	73,687	(2,623)
Other long-term assets	43,353		27,058	
Total intangibles and other long-term assets	$ 502,521	$ (99,541)	$ 428,662	$ (66,687)

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Aggregate amortization expense of intangible and other assets are as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Reported in depreciation and amortization	$ 17,462	$ 6,764	$ 15,532	$ 10,267
Reported in interest expense	$ 9,015	$ 2,716	$ 7,132	$ 3,702

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2009	$ 29,897
2010	27,984
2011	25,574
2012	20,179
2013	14,406

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. 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, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate segment and as of August 31 for all others. No impairment of intangible assets was required during the periods presented in these consolidated financial statements.

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.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2008	December 31, 2007
Operating expenses	$ 19,655	$ 19,773
Litigation, environmental and other contingencies	21,886	35,707
Taxes other than income taxes	20,772	48,437
Other	31,843	29,583
Total accrued and other current liabilities	$ 94,156	$ 133,500

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 December 31, 2008 was $6.41 billion and $7.24 billion, respectively. At December 31, 2007, the aggregate fair value and carrying amount of long-term debt was $5.87 billion and $5.92 billion, respectively.

We adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, (SFAS 157) effective January 1, 2008. SFAS 157 provides a definition of fair value, establishes a fair value framework and hierarchy under GAAP and provides for expanded disclosures of fair value measurements. SFAS 157 does not require any new fair value measurements other than those established by other GAAP requirements. As noted below, under New Accounting Standards, the effective date of SFAS 157 has been deferred with respect to certain non-financial assets and liabilities.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. In accordance with SFAS 157, we determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible Level as defined in SFAS 157. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (OTC) commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. Fair value measurements within the scope of SFAS 157 that require the use of significant unobservable inputs are considered as Level 3 valuations as defined by SFAS 157.

The following table summarizes the fair value of our financial assets and liabilities as of December 31, 2008, based on inputs used to derive their fair values in accordance with SFAS 157:

		Fair Value Measurements at Report Date Using	
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets			
Marketable Securities	$ 5,915	$ 5,915	$
Commodity Derivatives	111,513	106,090	5,423
Liabilities			
Commodity Derivatives	(43,336)		(43,336)
Interest Rate Derivatives	(220,806)		(220,806)
Total	$ (146,714)	$ 112,005	$ (258,719)

Changes in the fair value of our interest rate derivatives classified as Level 3 in the fair value hierarchy were as follows:

	Interest Rate Swap Derivatives
Beginning Balance January 1, 2008	$ (16,020)
Total losses on non-hedged interest rate derivatives	(7,230)
Purchases, issuances, settlements	3,377
Transfers to Level 2	19,873
Ending Balance December 31, 2008	$

Total unrealized losses during period related to open instruments recorded in non-hedged interest rate derivatives	$	(3,010)

During the year ended December 31, 2008, certain interest rate derivatives were transferred from Level 3 to Level 2 due to availability of observable significant inputs.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs (CIAC) are netted against our project costs as they are received, and any CIAC which exceeds our total projects costs is recognized as other income in the period in which it is realized. In March 2008, we received a reimbursement of $40.0 million related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million which is recorded in other income on our consolidated statement of operations for the year ended December 31, 2008.

Contributions in aid of construction costs were as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Received and netted against project costs	$ 50,050	$ 3,493	$ 10,463	$ 7,328
Recorded in other income	8,352	216	403	998
Total	$ 58,402	$ 3,709	$ 10,866	$ 8,326

Shipping and Handling Costs

We have classified $185.3 million, $48.6 million, $109.4 million and $108.4 million from producer payments for natural gas, compression and treating, which can be considered handling costs, as revenue for the years ended December 31, 2008, the four months ended December 31, 2007, and the fiscal years ended August 31, 2007 and 2006, respectively. Shipping and handling costs related to fuel sold are included in cost of products sold. The remaining costs of approximately $112.0 million, $30.7 million, $58.6 million and $69.6 million included in operating expenses reflect the cost of fuel consumed for compression and treating for the year ended December 31, 2008, the four months ended December 31, 2007, and the fiscal years ended August 31, 2007 and 2006, 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 governmental authorities on a net basis.

Issuances of Subsidiary Units

The Partnership accounts for the difference between the carrying amount of the Partnership s investment in ETP and the underlying book value arising from issuances of units by ETP as capital transactions rather than selecting the income recognition method as permitted by SEC Staff Accounting Bulletin (SAB) No. 51 (see Note 7). If ETP issues units at a price less than the Partnership s carrying value per unit, the Partnership assesses whether the investment in ETP has been impaired, in which case a provision would be reflected in the Partnership s consolidated statement of operations. The Partnership did not recognize any impairment related to the issuance of ETP units during the years ended December 31, 2008, August 31, 2007 or 2006, or the four months ended December 31, 2007.

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Income Taxes

ETE 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 profits 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.

We exceeded the 50% threshold on May 7, 2007, and, as a result, our partnership terminated for federal tax income purposes on that date. Our termination also caused ETP to terminate for federal income tax purposes on that date. These terminations did not affect our classification or the classification of ETP as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income or the qualifying income of ETP for federal income tax purposes. These terminations required both us and ETP to close our taxable years and to make new elections as to various tax matters. In addition, ETP was required to reset the depreciation schedule for its depreciable assets for federal income tax purposes. The resetting of ETP s depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to the Unitholders of ETP and, consequently, to our Unitholders. However, elections ETP and ETE made with respect to the amortization of certain intangible assets had the effect of reducing the amount of taxable income that would otherwise be allocated to ETE 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, ETP s subsidiary, Heritage Holdings, Inc. (HHI), which owns ETP s 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 ETP Common Units. The amount of such goodwill accumulated as of the date of ETP s acquisition of HHI (approximately $158.0 million) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. ETP accounts for HHI using the treasury stock method due to its ownership of ETP s Class E units. Due to the accounting principles outlined in Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109) and related Interpretations, ETP accounts for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of ETP s HHI purchase price allocation, which effectively results in a charge to ETP s 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 December 31, 2008, the four months ended December, 31, 2007, and 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 $3.4 million, $1.2 million and $1.2 million, respectively. As of December 31, 2008, the amount of tax goodwill to be amortized over the next 14 years for which HHI will receive a remedial income allocation is approximately $143.0 million.

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-qualifying 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 December 31, 2008, August 31, 2007 and 2006, and the four months ended December 31, 2007, our non-qualifying income did not, or was not expected to, exceed the statutory limit.

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Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes in accordance with SFAS 109. Under SFAS 109, deferred income taxes are recorded based upon differences between the financial reporting and tax basis 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) to account for our derivative financial instruments. SFAS 133 requires that all derivatives be measured at fair value on the balance sheet as either an asset or liability. For qualifying hedges, SFAS 133 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 formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

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 net income for the period.

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 accounted for as cash flow hedges are classified in other income for periods after August 31, 2006. For the year ended August 31, 2006, such gains or losses were reported in interest expense.

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

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 AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge s change in fair value is recognized each period in net income. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI 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 financial derivative instruments that are not designated hedges, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, our Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 7).

Unit-Based Compensation

We account for awards under our equity incentive plans in accordance with Statement of Financial Accounting Standards No. 123 (Revised 2004), *Share-Based Payment,* (SFAS 123R), which requires us to recognize compensation expense over the vesting period based on the grant-date fair value of equity awards issued to employees. The grant-date fair value is determined based on the market price of our Common Units on the grant date, adjusted to reflect the present value of any expected distributions that will not accrue to the employee during the vesting 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 based on the most recently declared distribution as of the grant date.

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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 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 interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We adopted FIN 48 on September 1, 2007, which adoption did not have a significant impact on our consolidated financial statements.

Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations,* (SFAS 141R). On December 4, 2007, the FASB issued SFAS 141R, which will significantly change the accounting for business combinations. Under SFAS 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. Statement 141R will change the accounting treatment for certain specific items, including:

Acquisition costs will generally be expensed as incurred;

Non-controlling interests (currently referred to as minority interests) will be valued at fair value at the acquisition date;

Acquired contingent liabilities will be recorded at fair value at the acquisition date and subsequently measured at either the higher of such amount or the amount determined under existing guidance for non-acquired contingencies;

In-process research and development will be recorded at fair value as an indefinite-lived intangible asset at the acquisition date;

Restructuring costs associated with a business combination will generally be expensed subsequent to the acquisition date; and

Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date generally will affect income tax expense.

SFAS 141R also includes a substantial number of new disclosure requirements. SFAS 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Early adoption is prohibited; therefore, SFAS 141R has not been applied to any transactions presented in these consolidated financial statements. Our adoption of SFAS 141R on January 1, 2009 did not have an immediate impact on our financial position or results of operations.

Statement of Financial Accounting Standards 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. The adoption of the measurement provisions of this statement on January 1, 2008 did not have a material impact on our consolidated financial statements.

Statement of Financial Accounting Standards 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. We did not elect the fair value option provisions upon adoption of SFAS 159 on January 1, 2008.

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Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51* (SFAS 160). On December 4, 2007, the FASB issued SFAS 160. SFAS 160 establishes new accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, SFAS 160 requires the recognition of a non-controlling interest (minority interest) as equity in the consolidated financial statements and separate from the parent s equity. The amount of net income attributable to the non-controlling interest will be included in consolidated net income on the face of the income statement. SFAS 160 clarifies that changes in a parent s ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, SFAS 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss will be measured using the fair value of the non-controlling equity investment on the deconsolidation date. SFAS 160 also includes expanded disclosure requirements regarding the interests of the parent and its non-controlling interest. SFAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. While the adoption of SFAS 160 will not have a significant impact on our consolidated financial position or results of operations, it will result in certain changes to our financial statement presentation, including the change in classification of non-controlling interest (minority interest) from liabilities to partners capital on the consolidated balance sheet.

Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133* (SFAS 161). Issued in March, 2008, SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement has the same scope as SFAS 133, and accordingly applies to all entities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 did not impact our financial position or results of operations.

EITF Issue No. 07-4, *Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships (MLP)* (EITF 07-4). The FASB ratified the final consensus on EITF 07-4 on March 26, 2008. The key elements of the final consensus relate to: (a) the scope of the issue; (b) when Incentive Distribution Rights (IDRs) are considered participating securities under the two-class method for Earnings Per Share (EPS); (c) the calculation provisions; and (d) the transition and effective date. EITF 07-4 addresses how current period earnings of an MLP should be allocated to the general partner, limited partners, and, when applicable, the holder of IDRs when applying the two-class method under Statement 128. EITF 07-4 applies to MLPs that are required to make incentive distributions when certain thresholds have been met regardless of whether the IDR is a separate limited partner interest or embedded in the general partner interest. EITF 07-4 only addresses incentive distributions that are treated as equity distributions and does not address whether the incentive distributions are compensation or equity distributions. Specifically, if IDRs are separate from the general partner interest, then they are considered separate participating securities for purposes of applying the two-class method of determining EPS. Under this situation, the two-class method is used to determine EPS for the general partner interest, limited partner interest and the IDR holders interest. EITF 07-4 provides that when earnings for the period exceed distributions, the excess undistributed earnings are to be allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of income. When distributions for the period exceed earnings, the income is first allocated equal to the actual distributions. The resulting deficit is allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of losses. EITF 07-4 is effective with the first fiscal year beginning after December 15, 2008, including interim periods within those fiscal years, and requires retrospective application of the guidance to all periods presented. Early application is prohibited. Our adoption of EITF 07-4 on January 1, 2009 did not have an impact on the calculation of ETE s earnings per unit.

FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). FSP EITF 03-6-1 was issued by the FASB on June 16, 2008. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We adopted FSP EITF 03-6-1 effective January 1, 2009. Based on unvested unit awards currently outstanding, application of FSP EITF 03-6-1 did not have a material impact on our computation of earnings per unit.

EITF Issue No. 08-6, *Equity Method Investment Accounting Considerations* (EITF 08-6). Ratified by the FASB on November 24, 2008, EITF 08-6 establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment. EITF 08-6 also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. EITF 08-6 is effective on a prospective basis for fiscal years beginning after December 15, 2008. We do not expect our adoption of EITF 08-6 on January 1, 2009 to have a material impact on our financial condition or results of operations.

Statement of Financial Accounting Standards Staff Position (FSP) SFAS 157-2, *Effective Date of FASB Statement No. 157 (FSP 157-2)*. FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As allowed under FSP 157-2, we have not applied the provisions of SFAS 157 to our nonfinancial assets and liabilities measured at fair value, which include impaired nonfinancial assets and certain assets and liabilities acquired in business combinations. We are currently evaluating the impact of our adoption of FSP 157-2 effective January 1, 2009 on our consolidated financial statements. Although our adoption of FSP 157-2 on January 1, 2009, may require additional disclosure, we do not expect an impact to our financial condition or results of operations.

3. SIGNIFICANT ACQUISITIONS AND JOINT VENTURES:

Joint Ventures

Midcontinent Express Pipeline LLC

In December 2006, we entered into an agreement with KMP for a 50/50 joint development of Midcontinent Express pipeline, 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, which is currently pending necessary regulatory approvals. In February 2007, MEP, the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the FERC s NEPA pre-filing review process. MEP filed its application with the FERC for a Certificate of Public Convenience and Necessity in October 2007. In June 2008, the FERC issued an order approving this application. Mobilization for construction of this pipeline commenced in September 2008, following FERC approval. The first phase of the pipeline is expected to be in service by the second quarter of 2009 and the second phase of the pipeline is expected to be in service by the third quarter of 2009. In July 2008, MEP completed an open season with respect to a capacity expansion of MEP from the original planned capacity of 1.5 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to a planned interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional 300 MMcf/d of capacity was fully subscribed as a result of this open season. The planned expansion of capacity would be effectuated through the installation of additional compression on this segment of the pipeline and is subject to MEP s filing of an application with, and approval from, the FERC.

ETP Enogex Partners LLC

In September 2008, we entered into an agreement with OGE Energy Corp. (OGE) to form a joint venture entity, ETP Enogex Partners LLC (ETP Enogex Partners), to which OGE would contribute its Enogex midstream business and we would contribute our 100% equity interest in Transwestern, our 50% equity interest in MEP, the entity formed to own and operate the

Midcontinent Express pipeline, and our 100% equity interest in ETC Canyon Pipeline, LLC, which we refer to as ETC Canyon Pipeline, which owns and operates the Canyon Gathering System. Subsequent to entering into this agreement, conditions in the credit markets deteriorated and the parties were not able to obtain financing on favorable terms. On February 12, 2009, ETP and OGE agreed to terminate the agreement to form a joint venture.

Fayetteville Express Pipeline LLC

In October 2008, we entered into an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 187-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. FEP, the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the FERC s NEPA pre-filing review process in November 2008. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the pipeline project is expected to be in service by early 2011. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (NGPL) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi, and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Knight, Inc. Knight owns the general partner of KMP. Pursuant to our agreement with KMP related to this project, we and KMP are each obligated to fund 50% of the equity necessary to construct the project.

Significant Acquisitions:

Fiscal 2008

During the year ended December 31, 2008, HOLP and Titan collectively acquired substantially all of the assets of 20 propane businesses. The aggregate purchase price for these acquisitions totaled $96.4 million which included $76.2 million of cash paid, net of cash acquired, liabilities assumed of $ 8.2 million, 53,893 Common Units issued valued at $2.2 million and debt forgiveness of $9.8 million. The cash paid for acquisitions was financed primarily with ETP s and HOLP s Senior Revolving Credit Facilities. We recorded $15.3 million of goodwill in connection with these acquisitions.

Transition Period 2007

Canyon Acquisition

In October 2007, ETP acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the Canyon acquisition) for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The Canyon Gathering System has over 400,000 dedicated acres under long-term contracts. The Canyon assets include a gathering system in the Piceance-Uinta Basin which consists of over 1,300 miles of 2-inch to 16-inch pipe with a projected capacity of over 300 MMcf/d, as well as six conditioning 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 results of the Canyon Gathering System are included in our midstream segment since the acquisition date.

The Canyon acquisition was accounted for under the purchase method of accounting in accordance with Statement of Financial Accounting Standards No. 141, *Business Combinations*, (SFAS 141). The purchase price was initially allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. We completed the purchase price allocation during the third quarter of 2008. The adjustments to the purchase price allocation were not material. The final allocations of the purchase price are noted below:

Accounts receivable	$ 3,613
Inventory	183
Prepaid and other current assets	1,606
Property, plant, and equipment	284,910
Intangibles and other assets	6,351
Goodwill	11,359
Total assets acquired	308,022

Accounts payable	(1,840)
Customer advances and deposits	(1,030)
Total liabilities assumed	(2,870)
Net assets acquired	$ 305,152

Fiscal 2007

On November 1, 2006, the Parent Company acquired from Energy Transfer Investments, L.P. (ETI , a partnership also controlled by LE GP) the remaining 50% of the Class B Limited Partner interests in ETP GP owned by ETI. The Parent Company recorded this acquisition at ETI s historical cost of $4.5 million as required under GAAP due to the fact that the Parent Company and ETI are companies under common control. As a result, the Parent Company now owns 100% of the Incentive Distribution Rights of ETP. The acquisition was effected through the issuance of 83,148,900 newly created Parent Company Class C Units and the assumption by the Parent Company of approximately $70.5 million of ETI s indebtedness. The assumption of this debt represents a non-cash financing activity. The Class C Units were recorded at the net value of the debt assumption (accounted for as a distribution to ETI) and the value of the ETP GP Class B Units acquired, a net amount of $66.0 million. The Class C Units had essentially the same voting rights and rights to distributions as the Common Units and Class B Units. The Class C Units converted into Common Units upon approval by the ETE Common Unitholders on February 22, 2007.

Also on November 1, 2006, the Parent Company acquired additional limited partner interests in ETP (Class G Units, which subsequently converted to Common Units on May 1, 2007, see Note 7) which increased the Parent Company s aggregate ownership in ETP s limited partner interests to approximately 46%.

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (GE) and Southern Union Company (Southern Union), ETP acquired the member interests in CCE Holdings, LLC (CCEH) from GE and certain other investors for $1.00 billion. ETP financed a portion of the CCEH purchase price with the proceeds from its issuance of 26,086,957 Class G Units to the Parent Company 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.

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, ETP acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of approximately $30.6 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems

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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 March 2008, a contingent payment of $8.7 million was recorded as an adjustment to goodwill in the midstream segment.

In December 2006, ETP purchased a natural gas gathering system in north Texas for $32.0 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $21.0 million to be determined two years after the closing date. In December 2008, it was determined that a contingency payment would not be required. 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 $17.6 million which included $15.5 million of cash paid, net of cash acquired, and liabilities assumed of $2.1 million. The cash paid for acquisitions was financed primarily with ETP s and HOLP s Senior Revolving Credit Facilities.

Except for the acquisition of the interests in ETP GP, the purchase of Class G Units from ETP and the 50% member interests in CCEH, the acquisitions discussed above 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. The acquisition of the interests in ETP GP was accounted for on the basis of historical costs, as discussed above. The purchase of Class G Units from ETP was accounted for as described in Note 7. Pro forma effects of the Transwestern acquisition and the purchase of additional interests in ETP GP and ETP are discussed below. In the aggregate, the other acquisitions described above are not material for pro forma disclosure purposes.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for the 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 was 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 were completed during the first quarter of fiscal year 2008. The final allocation adjustments were not significant.

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Included in the property, plant and equipment associated with the Transwestern acquisition is an aggregate plant acquisition adjustment of $446.2 million, 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 $419.6 million at December 31, 2008 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 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
Cash Balance Plan	9,329
Total Regulatory Assets acquired	$ 69,957

All of Transwestern s regulatory assets are considered probable of recovery in rates.

We recorded the following intangible assets and goodwill in conjunction with the fiscal 2007 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 February 8, 2006, the Parent Company purchased 1,069,850 Common Units and 2,570,150 Class F Units representing limited partnership interests in ETP. This purchase increased the Parent Company s ownership percentage in ETP limited partners interests from approximately 31% to approximately 33%. The Class F Units were converted to ETP Common Units on August 16, 2006.

On November 10, 2005, we acquired the remaining 2% limited partnership interests in the HPL System for $16.6 million 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.

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On June 1, 2006, we acquired all the propane operations of Titan for cash of approximately $548.0 million, after working capital adjustments and net of cash acquired, and liabilities assumed of approximately $46.0 million. This acquisition was initially financed by borrowings under the ETP 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 price 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 $28.9 million which included $20.6 million of cash paid, net of cash acquired, 99,955 ETP Common Units issued valued at $4.0 million and liabilities assumed of $4.3 million. 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 fiscal year 2006 acquisitions:

	Titan Acquisition	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	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 the fiscal 2006 acquisitions:

Customer lists (3 to15 years)	$ 37,333
Non-compete agreements (5 to 10 years)	2,315
Software	2,200
Total amortizable 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

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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 expect all of the 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 and the Parent Company s acquisition of ETP Class G Units and the ETI transaction had been consummated 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 and the Parent Company s acquisition of ETP Class G Units and the ETI transaction and the acquisition of ETP Common and Class F Units had been consummated on September 1, 2005.

	Years Ended August 31,	
	2007	2006
Revenues	$ 6,850,929	$ 8,421,824
Net income	$ 317,541	$ 136,142
Limited Partners interest in net income	$ 316,499	$ 135,711
Basic earnings per Limited Partner Unit	$ 1.45	$ 0.60
Diluted earnings per Limited Partner Unit	$ 1.45	$ 0.60

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 Canyon acquisition, (2) the acquisition of the remaining 2% interest of HPL and (3) all other midstream and propane acquisitions, as these acquisitions did not meet the significance thresholds to require pro forma information. 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.

4. NET INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner s interest, by the weighted average number of limited partner interests outstanding. Diluted net income per limited partner unit is computed by dividing net income (as adjusted as discussed herein), after considering the General Partner s interest, by the weighted average number of limited partner interests outstanding and the number of unvested ETE Incentive Units granted. For the diluted earnings per share computation, income allocable to the limited partners is reduced, where applicable, for the decrease in earnings from ETE s limited partner unit ownership in ETP that would have resulted assuming the incremental units related to ETP s equity incentive plans had been issued during the respective periods. Such units have been determined based on the treasury stock method.

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

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Basic Net Income per Limited Partner Unit:				
Limited Partner s interest in net income	$ 373,883	$ 92,390	$ 318,312	$ 106,531
Weighted average limited partner units	222,829,956	222,829,916	204,578,719	133,820,176
Basic net income per limited partner unit	$ 1.68	$ 0.41	$ 1.56	$ 0.80
Diluted Net Income per Limited Partner Unit:				
Limited Partner s interest in net income	$ 373,883	$ 92,390	$ 318,312	$ 106,531
Dilutive effect of Unit Grants	(349)	(218)	(376)	(343)
Diluted net income available to limited partners	$ 373,534	$ 92,172	$ 317,936	$ 106,188
Weighted average limited partner units	222,829,956	222,829,916	204,578,719	133,820,176
Diluted net income per limited partner unit	$ 1.68	$ 0.41	$ 1.55	$ 0.79

5. MINORITY INTERESTS:

The following table summarizes the changes in minority interest liability:

	December 31, 2008	December 31, 2007
Balance, beginning of the period	$ 2,106,819	$ 1,882,432
Minority interest in net income of subsidiaries	304,710	90,132
Distributions and other	(319,963)	(63,756)
Subsidiary sale of common units (see Note 7)	(48,782)	(48,932)
Compensation under employee unit awards by subsidiary	23,481	8,114
Non-cash executive compensation	1,202	1,167
ETP units tendered by employees to pay taxes	(3,513)	(164)
Change in accumulated other comprehensive income allocable to minority interests	(13,086)	2,700
Subsidiary units issued in connection with public offering	373,059	234,887
Subsidiary units issued in connection with certain acquisitions	2,228	1,400
Impact of remedial tax allocation	(3,407)	(1,161)
Balance, end of the period	$ 2,422,748	$ 2,106,819

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6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2008	December 31, 2007	Maturities
ETP Senior Notes:			
9.70% Senior Notes, net of discount of $432	$ 599,568	$	One payment of $600,000 due March 15, 2019. Interest is paid semi-annually. Put option on March 15, 2012.
6.0% Senior Notes, net of discount of $579	349,421		One payment of $350,000 due July 13, 2013. Interest is paid semi-annually.
6.7% Senior Notes, net of discount of $1,672	598,328		One payment of $600,000 due July 2, 2018. Interest is paid semi-annually.
7.5% Senior Notes, net of discount of $5,703	544,297		One payment of $550,000 due July 1, 2038. Interest is paid semi-annually.
6.125% Senior Notes, net of discount of $295 and $322, respectively	399,705	399,678	One payment of $400,000 due February 15, 2017. Interest is paid semi-annually.
6.625% Senior Notes, net of discount of $2,204 and $2,231, respectively	397,796	397,769	One payment of $400,000 due October 15, 2036. Interest is paid semi-annually.
5.95% Senior Notes, net of discount of $1,530 and $1,733, respectively	748,470	748,267	One payment of $750,000 due February 1, 2015. Interest is paid semi-annually.
5.65% Senior Notes, net of discount of $231 and $288, respectively	399,769	399,712	One payment of $400,000 due August 1, 2012. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Notes, including premium of $3,499 and $4,077, respectively	91,499	92,077	One payment of $88,000 due November 17, 2014. Interest is paid semi-annually.
5.54% Senior Unsecured Notes, net of discount of $4,330 and $4,855, respectively	120,670	120,145	One payment of $125,000 due November 17, 2016. Interest is paid semi-annually.
5.64% Senior Unsecured Notes	82,000	82,000	One payment due May 24, 2017. Interest is paid semi-annually.
5.89% Senior Unsecured Notes	150,000	150,000	One payment due May 24, 2022. Interest is paid semi-annually.
6.16% Senior Unsecured Notes	75,000	75,000	One payment due May 24, 2037. Interest is paid semi-annually.

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HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	36,000	48,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
Medium Term Note Program:			
7.17% Series A Senior Secured Notes	2,400	4,800	Annual payments of $2,400 due each November 19 through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	8,000	10,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	9,142	13,714	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	11,500	15,500	Annual payments of $5,750 due each August 15, 2009 and 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	45,550	58,000	Annual payments of $12,450 due August 15, 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	Paid and retired in May 2008.
7.89% Series H Senior Secured Notes	5,818	6,545	Annual payments of $727 due each May 15 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 and Term Loans:			
ETE Senior Secured Revolving Credit Facility (including Swingline loan option)	121,642	122,643	Available through February 8, 2011. See terms below under Parent Company Credit Facilities .
ETE Senior Secured Term Loan	1,450,000	1,450,000	Due November 1, 2012. See terms below under Parent Company Credit Facilities .
ETP Revolving Credit Facility (including Swingline loan option)	902,000	1,626,948	Available through July 2012 see terms below under ETP Credit Facility .
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	15,000	Available through June 30, 2011 - see terms below under HOLP Credit Facility .
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 7.91% and 5.51 % for December 31, 2008 and 2007, respectively	11,249	11,171	Due in installments through 2014.
Other	2,765	3,405	Due in installments through 2024.
	7,235,589	5,917,174	
Current maturities	(45,232)	(47,068)	
	$ 7,190,357	$ 5,870,106	

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

2009	$ 45,232
2010	40,766
2011	166,096
2012	2,774,896
2013	372,412
Thereafter	3,836,187
	$ 7,235,589

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). 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 and related indenture supplements related to the ETP Senior Notes.

The ETP Senior Notes are unsecured obligations of ETP and the obligation of ETP to repay the ETP Senior Notes is not guaranteed by us, ETP or any of ETP s subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours, ETP s or its 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 ETP s existing and future subsidiaries.

ETP 9.70% Senior Notes

In December 2008, ETP completed a public offering of $600.0 million aggregate principal amount of 9.70% Senior Notes due 2019 the (ETP 9.70% Senior Notes). The holders of the ETP 9.70% Senior Notes have the right to require us to repurchase all or a portion of the notes on March 15, 2012 at the principal amount plus any accrued interest as of that date. We used the proceeds of approximately $595.7 million (net of bond discounts of $0.4 million and other offering costs of $3.9 million) from the issuance of the ETP 9.70% Senior Notes to repay other indebtedness.

Interest on the ETP 9.70% Senior Notes is payable semiannually on March 15 and September 15 of each year. The Partnership may redeem some or all of the ETP 9.70% Senior Notes at any time, or from time to time, pursuant to the terms of the indenture.

ETP 2008 Senior Notes

In March 2008, ETP issued a total of $1.50 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the ETP 2008 Senior Notes). ETP used the proceeds of approximately $1.48 billion, net of bond discounts and other offering costs, from the issuance of the ETP 2008 Senior Notes to repay borrowings and accrued interest outstanding under the $500.0 million, 364-day term loan credit facility (the ETP 364-Day Credit Facility) and to repay a portion of amounts outstanding under the ETP Credit Facility and other indebtedness. Interest on the ETP 2008 Senior Notes is payable semiannually on January 1 and July 1 of each year. The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture.

The ETP 364-Day Credit Facility was a single draw term loan used for general corporate purposes, under which ETP borrowed the entire amount available under this facility on February 12, 2008, with an applicable Eurodollar rate plus 1.000% per annum based on the current rating by the rating agencies or at the Base Rate for a designated period. The indebtedness under the ETP 364-Day Credit Facility was unsecured and not guaranteed by us or ETP or any of our or ETP s subsidiaries.

ETP 2006 Senior Notes

In October 2006, we issued a total of $400.0 million of 6.125% Senior Notes due 2017 and $400.0 million of 6.625% Senior Notes due 2036 (collectively, the ETP 2006 Senior Notes). Interest on the senior notes due 2017 is payable semi-annually on February 15 and August 15 of each year, beginning February 15, 2007, and interest on the senior notes due 2036 is payable semi-annually on April 15 and October 15 of each year, beginning April 15, 2007.

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ETP 2005 Senior Notes

In July 2005, we issued a total of $400.0 million of 5.65% Senior Notes due 2012 (the ETP 5.65% Senior Notes). Interest on the ETP 5.65% Senior Notes is payable semi-annually on February 1 and August 1 of each year, beginning on February 1, 2006.

In January 2005, we issued a total of $750.0 million of 5.95% Senior Notes due 2015 (the ETP 5.95% Senior Notes, and collectively with the ETP 5.65% Senior Notes, the ETP 2005 Senior Notes). Interest on the ETP 5.95% Senior Notes is payable semi-annually on February 1 and August 1 of each year, beginning on August 1, 2005.

Transwestern Senior Unsecured Notes

Transwestern s long-term debt consists of $213.0 million remaining principal amount of notes assumed in connection with the Transwestern acquisition and $307.0 million in principal amount of notes issued in May 2007, the proceeds from which were used to repay other indebtedness and for general corporate purposes. No principal payments are required under any of the Transwestern notes prior to their respective maturity dates. The Transwestern notes rank pari passu with Transwestern s other unsecured debt. The Transwestern 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 (collectively, the HOLP 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 December 31, 2008 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

Revolving Credit Facilities and Term Loans

Parent Company Facilities

The Parent Company has a $1.45 billion Term Loan Facility and a Term Loan Maturity Date of November 1, 2012 (the Parent Company Credit Agreement). The Parent Company Credit Agreement also includes a $500.0 million Secured Revolving Credit Facility (the Parent Company Revolving Credit Facility) available through February 8, 2011. The Parent Company Revolving Credit Facility includes a Swingline loan option with a maximum borrowing of $10.0 million and a daily rate based on LIBOR.

The total outstanding amount borrowed under the Parent Company Credit Agreement and the Parent Company Revolving Credit Facility as of December 31, 2008 was $1.57 billion. The total amount available under the Parent Company s debt facilities as of December 31, 2008 was $0.38 billion. The Parent Company Revolving Credit Facility also contains an accordion feature which will allow the Parent Company, subject to bank syndication s approval, to expand the facility s capacity up to an additional $100.0 million.

The maximum commitment fee payable on the unused portion of the Parent Company Revolving Credit Facility is based on the applicable Leverage Ratio which is currently at Level III or 0.375%. Loans under the Parent Company Revolving Credit Facility bear interest at Parent Company s option at either (a) the Eurodollar rate plus the applicable margin or (b) base rate plus the applicable margin. The applicable margins are a function of the Parent Company s leverage ratio that corresponds to levels set forth in the agreement. The applicable Term Loan bears interest at (a) the Eurodollar rate plus 1.75% per annum and (b) with respect to any Base Rate Loan, at Prime Rate plus 0.25% per annum. As of December 31, 2008, the weighted average interest rate was 4.11% for the amounts outstanding on the Parent Company Senior Secured Revolving Credit Facility and the Parent Company $1.45 billion Senior Secured Term Loan Facility.

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The Parent Company Credit Agreement is secured by a lien on all tangible and intangible assets of the Parent Company and its subsidiaries, including its ownership of 62,500,797 ETP Common Units, the Parent Company s 100% interest in ETP LLC and ETP GP with indirect recourse to ETP GP s 2% General Partner interest in ETP and 100% of ETP GP s outstanding incentive distribution rights in ETP, which the Parent Company holds through its ownership of ETP GP.

ETP Credit Facility

The ETP Credit Facility provides for $2.00 billion of revolving credit capacity that is expandable to $3.00 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity, under the Amended and Restated Credit Agreement). 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). 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 includes a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2.00 billion unless expanded to $3.00 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%.

As of December 31, 2008, there was a balance outstanding in the ETP Credit Facility of $902.0 million in revolving credit loans with no outstanding balance in swingline loans, and approximately $60.0 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2008, was 2.82%. The total amount available under the ETP Credit Facility, as of December 31, 2008, which is reduced by any letters of credit, was approximately $1.04 billion ($1.27 billion on a pro forma basis after giving effect to the $225.9 million of net proceeds from our equity offering in January 2009). The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership s subsidiaries and has equal rights to holders of our current and future unsecured debt. In connection with entering into the credit agreement for the ETP Credit Facility (July 2007), 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.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available to HOLP through June 30, 2011, which may be expanded to $150.0 million. The HOLP Credit Facility includes a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Credit 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 Credit Facility (total book value as of December 31, 2008 of approximately $1.3 billion). At December 31, 2008, there was $10.0 million outstanding on the revolving credit loans. A letter of credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Credit Facility. There were outstanding letters of credit of $1.0 million at December 31, 2008. The sum of the loans made under the HOLP Credit Facility plus the letter of credit exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Credit Facility. The amount available as of December 31, 2008 was $64.0 million.

Debt Covenants

The agreements related to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

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The agreements and indentures related to each of the Parent Company Revolving Credit Facility and Senior Secured Term Loan Facility and ETP s and the Operating Partnerships HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to the Parent Company, ETP and the Operating Partnerships, including the maintenance of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens as described in more detail below.

The Parent Company Revolving Credit Facility and Senior Secured Term Loan Facility contain financial covenants as follows:

- Maximum Leverage Ratio Consolidated Funded Debt of the Parent Company (as defined) to Consolidated EBITDA (as defined in the agreements) of the Parent Company of not more than 4.50 to 1.00, with a permitted increase to 5.00 to 1.00 during a specified acquisition period extending for two fiscal quarters following the close of a specified acquisition

- Maximum Consolidated Leverage Ratio Consolidated Funded Debt of the Parent Company and ETP to Consolidated EBITDA of ETP of not more than 5.50 to 1.00

- Interest Coverage Ratio may not be less than 3.00 to 1.00

- Value to Loan Ratio may not be less than 2.00 to 1.00

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 (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);

- 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.

The credit agreement related to the ETP Credit Facility also contains a financial covenant that provides that on each date ETP 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 defined in the ETP Credit Facility.

The agreements related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to HOLP, including the maintenance of various financial and leverage covenants and limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The financial covenants require HOLP to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not less than 2.25 to 1. These debt agreements also provide that HOLP 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 the amount of Available Cash (as defined in the agreements related to the HOLP Notes and HOLP Credit Facility) with respect to the immediately preceding quarter (which amount is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes during the last quarter 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 HOLP Notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates), (b) no default or event of default exists before such restricted payments, and (c) the amounts of HOLP s restricted payment is not disproportionately greater than the payment amount from ETC OLP utilized to fund payment obligations of ETP and its general partner with respect to ETP s Common Units.

Failure to comply with the various restrictive and affirmative covenants of our bank credit facilities and the note agreements related to the HOLP Notes 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 December 31, 2008.

7. PARTNERS CAPITAL:

Limited Partner Units

Limited partner interests in the Partnership are represented by Common Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. The Partnership s 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 the Partnership s 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.

As of December 31, 2008, there were issued and outstanding 222,829,956 Common Units representing an aggregate 99.69% limited partner interest in the Partnership.

Our Partnership Agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. For any fiscal year that the Partnership has net profits, such net profits are first allocated to the General Partner until the aggregate amount of net profits for the current and all prior fiscal years equals the aggregate amount of net losses allocated to the General Partner for the current and all prior fiscal years. Second, such net profits shall be allocated to the Limited Partners pro rata in accordance with their respective sharing ratios. For any fiscal year in which the Partnership has net losses, such net losses shall be first allocated to the Limited Partners in proportion to their respective adjusted capital account balances, as defined by the Partnership Agreement, (before taking into account such net losses) until their adjusted capital account balances have been reduced to zero. Second, all remaining net losses shall be allocated to the General Partner. The General Partner may distribute to the Limited Partners funds of the Partnership that the General Partner reasonably determines are not needed for the payment of existing or foreseeable Partnership obligations and expenditures.

On February 8, 2006 we completed our IPO of 24,150,000 Common Units at a price of $21.00 per unit. In connection with this IPO, the Partnership s limited partner units were converted to Common Units based on a conversion ratio of 54.41% (46.48% after the dilution effects of the IPO and issuance of Class B Units). Proceeds, net of the underwriters discount and equity issue costs, were $474.7 million. We used a portion of the net proceeds of the IPO to redeem 6,650,000 Common Units from the then existing limited partners. We used the remaining net proceeds from the offering to repay outstanding indebtedness plus accrued interest of the Partnership and to fund the purchase of 1,069,850 ETP Common Units and 2,570,150 ETP Class F Units for $132.4 million ($36.37 per ETP Unit) and for general partnership purposes.

Upon the closing of the IPO, we also issued Class B Units to our management. Each Class B Unit represented a limited partner interest in the Partnership and was convertible into a Common Unit on a one-for-one basis at the election of the holder at any time following the six month anniversary of their issuance. On March 27, 2007, all 136,357,870 outstanding Limited Partner Class B Units were converted to Common Units.

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Common Units

The change in Common Units is as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31,	
			2007	2006
Number of Units, beginning of period	222,829,956	222,828,332	124,360,520	
Common Units issued to limited partner interests at IPO				116,503,277
Units issued in IPO				24,150,000
Redemptions, as discussed above				(6,650,000)
Repurchase of Common Units				(9,642,757)
Issuance of resctricted Common Units under long-term incentive plan		1,624	1,948	
Issuance of Common Units			12,795,394	
Conversion of Class B Units to Common Units			2,521,570	
Conversion of Class C Units to Common Units			83,148,900	
Number of Units, end of period	222,829,956	222,829,956	222,828,332	124,360,520

In July 2006, ETE agreed to repurchase 9,642,757 of its Common Units for $237.8 million in an unsolicited offer from a former Unitholder. The Common Units were retired and canceled. The per unit price paid on the repurchase of units approximated the quoted market price at close, on the date of purchase, discounted at approximately 5%.

On November 28, 2006 the Parent Company sold 7,789,133 Common Units to a group of institutional investors in a private placement at a price of $27.41 per unit, resulting in net proceeds of approximately $213.5 million. The Parent Company used the proceeds to repay indebtedness under its credit facility.

On March 2, 2007 the Parent Company issued 5,006,261 Common Units in a private placement to a group of institutional investors. The units were issued at a price of $31.96 per unit resulting in approximately $160.0 million in net proceeds to the Parent Company. The proceeds were used to repay Parent Company indebtedness.

In connection with the private placements in November 2006 and March 2007, the Parent Company executed a registration rights agreement under which it agreed to file a shelf registration statement under the Securities Act within 90 days of closing of the private placement. The Form S-3 was filed on September 25, 2007. The Form S-3 provides for a primary offering of Common Units up to a total of $2.00 billion and a secondary offering of approximately 66,600,000 Common Units by selling Unitholders.

In connection with the March 2007 private placement of 5,006,261 units, the Parent Company executed a registration rights agreement under which it agreed to file a shelf registration statement under the Securities Act within 120 days of closing of the private placement (the closing). If the shelf registration statement was not declared effective within 180 days after closing or after becoming effective, or ceased to be effective during the Effectiveness Period (defined as the period during which there are registerable units outstanding) for any period of time in excess of 30 days, each purchaser of the units would be entitled to the payment of liquidated damages. The payment would be equal to 1.0% of the unit purchase price per 30-day period following the 180 day effectiveness period. In certain circumstances, the payment could be made using additional ETE Common Units. For the four months ended December 31, 2007, an expense of $7.8 million has been recorded in other, net in our consolidated statements of operations for liquidated damages under this registration rights agreement and the registration rights agreement entered into in connection with the November 2006 private placement because the shelf registration was not declared effective within the required timeframe. The liquidated damages were paid to entitled purchasers in December 2007. The S-3 registration statement became effective in October 2007.

On May 7, 2007, Enterprise GP Holdings, L.P. (EPE) acquired 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE), held by Ray C. 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. and affiliates of each. Neither ETE nor ETP issued any new units in this transaction. ETE granted EPE registration rights with respect to the Common Units acquired. The

registration rights provided to EPE require ETE to file a shelf registration statement upon demand by EPE for the number of ETE units EPE elects to sell and allows EPE to participate in a piggyback registration if ETE files a registration statement on its own behalf. ETE is required to pay all registration costs associated with the demand registration and piggyback participation. The registration statement demand can be made by EPE anytime beginning six months after the date of EPE s unit acquisition (defined as the Initial Restriction Expiration Date), and EPE can make such demand no more than three times. The piggyback participation rights expire two years after the Initial Restriction Expiration Date.

Class B Units

The change in Class B Units is as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31,	
			2007	2006
Number of Units, beginning of period			2,521,570	
Units issued to management, as discussed above				2,521,570
Conversion of Class B Units to Common Units			(2,521,570)	
Number of Units, end of period				2,521,570

During fiscal year 2006, we recognized compensation expense of $53.0 million for the grant-date fair market value of the Class B Units issued.

Class C Units

On November 1, 2006, the Parent Company acquired from Energy Transfer Investments, L.P. (ETI) the remaining 50% of the Class B Limited Partner interests in ETP GP with the issuance of 83,148,900 Class C Units, which the Parent Company recorded at ETI s historical cost of $4.5 million, net of long-term debt assumed of $70.5 million, a net amount of ($66.0 million) (see Note 2).

On February 22, 2007, at a special unitholders meeting, the Common Unitholders of ETE approved a proposal to convert ETE s Class C Units into 83,148,900 ETE Common Units. Following such approval, the Class C Units were converted into Common Units.

Sale of Common Units by Subsidiary

On February 8, 2006, ETE purchased 1,069,850 Common Units and 2,570,150 Class F Units representing limited partnership interests in ETP. The price per unit 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 ETP s Common Units on February 8, 2006. The Partnership recorded the premium of $54.0 million between the underlying book value before and after the purchase of the ETP Units as a reduction of ETE s limited partners capital with an adjustment to the minority interest to account for the effect of the increase in ETE s ownership percentage in ETP from 30.63% to 32.92%. We purchased the ETP Class F Units in a private placement. The terms of such Class F Units provided that they may be converted into Common Units upon an approval by a majority of the ETP Common Unitholders and that such units were entitled to distributions. The Class F Units were converted to ETP Common Units on August 16, 2006.

On November 1, 2006, the Parent Company purchased 26,086,957 Class G Units representing limited partnership interests in ETP. The price per unit paid for each of the Common Units was equal to $46.00 per unit, based upon a market discount from the New York Stock Exchange closing price of the ETP s Common Units on October 31, 2006 of $48.94. ETP used a portion of the proceeds to purchase interests in CCEH (see Note 3). The Parent Company has been granted registration rights in connection with the issuance of the ETP Class G Units. On May 1, 2007 the Unitholders of ETP approved the conversion of the Class G Units to Common Units and all the outstanding ETP Class G Units converted to ETP Common Units on a one-for-one basis on such date.

The Parent Company recorded the premium of $451.2 million (the difference between the Parent Company s share of the underlying book value in ETP before and after the purchase of the Class G Units) as a reduction of the Parent Company s

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limited partners capital with a corresponding increase in minority interest. The Parent Company s ownership percentage in ETP limited partner interests as a result of the Class G Unit purchase increased from approximately 33% to approximately 46%.

On January 8, 2008, ETP issued 750,000 ETP Common Units at $48.81 per ETP Common Unit to the underwriters pursuant to the exercise of a 30-day option to purchase Common Units to cover over-allotments in connection with ETP s December 2007 public offering of 5,000,000 ETP Common Units. The proceeds of $35.0 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility.

On July 21, 2008, ETP issued 8,912,500 ETP Common Units at $39.45 per ETP Common Unit in connection with a public offering. ETP used net proceeds of approximately $338.0 million to repay a portion of the amount outstanding under the ETP Credit Facility.

On January 27, 2009, ETP closed a public offering of 6,900,000 Common Units at $34.05 per ETP Common Unit. Net proceeds from the offering were used by ETP to repay approximately $225.9 million of outstanding debt under the ETP Credit Facility. ETP expects to use some of the increased availability under the revolving credit facility to finance capital expenditures and other growth projects.

The Parent Company recorded the difference of $48.8 million between the carrying amount of the Partnership s investment in ETP and its share of the underlying book value after giving effect to the above 2008 transactions as a capital transaction based on the Partnership s ownership in ETP s limited partner interests being diluted from 43.99% to 41.09% during the year ended December 31, 2008. The capital transaction is reflected in the Partnership s consolidated balance sheet at December 31, 2008 as an increase in limited partners capital in accordance with the guidance in SAB 51. No deferred taxes were recorded and the transaction had no effect on the Partnership s income.

Contributions to Subsidiary

The Parent Company indirectly owns the entire 2% general partner interest in ETP through its ownership of ETP GP, the general partner of ETP. ETP GP is required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions in order to maintain its 2% general partner interest in ETP. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP. ETP GP was required to contribute approximately $8.0 million for the year ended December 31, 2008, $5.0 million for the four months ended December 31, 2007, and $24.5 million and $2.8 million for the years ended August 31, 2007 and 2006, respectively.

Parent Company Quarterly Distributions of Available Cash

Our distribution policy is consistent with the terms of our Partnership Agreement, which requires that we distribute all of our available cash quarterly. We currently have no independent operations outside of our interests in ETP.

Our only cash-generating assets currently consist of distributions from ETP related to the following limited and general partner interests, including incentive distribution rights in ETP:

- ETE s ownership of the 2% general partner interest in ETP, which it holds through its ownership interests in ETP GP.

- 62,500,797 ETP Common Units representing approximately 41% of the total outstanding ETP Common Units, which ETE holds directly; and

- 100% of the incentive distribution rights in ETP, which ETE holds through its ownership interests in ETP GP and which entitle it to receive specified percentages of the cash distributed by ETP as ETP s per unit distribution increases. The Parent Company s incentive distribution rights entitle it to receive incentive distributions to the extent that quarterly distributions to ETP s Unitholders exceed $0.275 per unit ($1.10 per unit on an annualized basis). These incentive distributions entitle the Parent Company to increasing percentages of ETP s cash distributions based upon exceeding incentive distribution thresholds specified in ETP s Partnership Agreement, which incentive distribution rights entitle the Parent Company to receive 50% of ETP s cash distributions in excess of $0.4125 per unit. At ETP s current distribution levels, the Parent Company is entitled to receive cash distributions at the highest incentive distribution level of 50% with respect to ETP s distributions in excess of $0.4125 per unit.

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The total amount of distributions the Parent Company received from ETP relating to its limited partner interests, general partner interests and incentive distribution rights of ETP are as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Limited Partners Interests	$ 236,331	$ 51,563	$ 174,969	$ 80,203
General Partner Interest	17,851	3,553	12,701	6,931
Incentive Distribution Rights	305,072	59,315	183,056	64,436
Less holdback (a)	(13,098)			(2,287)
Total distributions received from ETP	$ 546,156	$ 114,431	$ 370,726	$ 149,283

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(a) Represents amounts held back for reimbursement of expenses and contributions required to maintain ETP GP s 2% General Partner interest in ETP.

Our distributions declared since our IPO in February 2006 are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2008	November 10, 2008	November 19, 2008	$ 0.4800
	August 7, 2008	August 19, 2008	0.4800
	May 5, 2008	May 19, 2008	0.4400
	February 1, 2008 (1)	February 19, 2008	0.5500
Transition Period Ended December 31, 2007	October 5, 2007	October 19, 2007	$ 0.3900
Fiscal Year Ended August 31, 2007	July 2, 2007	July 19, 2007	$ 0.3725
	April 9, 2007	April 16, 2007	0.3560
	January 4, 2007	January 19, 2007	0.3400
	October 5, 2006	October 19, 2006	0.3125
Fiscal Year Ended August 31, 2006	June 30, 2006	July 19, 2006	$ 0.2375
	March 31, 2006	April 19, 2006	0.0578

On January 26, 2009, the Parent Company announced the declaration of a cash distribution for the fourth quarter ended December 31, 2008 of $0.51 per Common Unit, or $2.04 annually, an increase of $0.12 per Common Unit on an annualized basis. We paid this distribution on February 19, 2009 to Unitholders of record at the close of business on February 6, 2009.

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The total amount of distributions we have declared is as follows (all from Available Cash from our operating surplus):

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Limited Partners -				
Limited Partners	$	$	$	$ 34,010
Common Units	434,519	86,904	246,136	65,905
Class B Units			1,645	745
Class C Units			28,261	
General Partner	1,349	270	955	599
Total distributions declared	$ 435,868	$ 87,174	$ 276,997	$ 101,259

ETP s Quarterly Distribution of Available Cash

ETP s Partnership Agreement requires that ETP distribute all of its Available Cash to its Unitholders and its 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 fiscal quarter of ETP, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by its General Partner in its sole discretion to provide for the proper conduct of ETP s 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 ETP s Partnership Agreement.

ETP s distributions declared during the periods presented below are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2008	November 10, 2008	November 14, 2008	$ 0.89375
	August 7, 2008	August 14, 2008	0.89375
	May 5, 2008	May 15, 2008	0.86875
	February 1, 2008 (1)	February 14, 2008	1.12500
Transition Period Ended December 31, 2007	October 5, 2007	October 15, 2007	$ 0.82500
Fiscal Year Ended August 31, 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 Ended August 31, 2006	June 30, 2006	July 14, 2006	$ 0.63750
	June 30, 2006 (2)	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

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(1) One-time four month distribution On January 18, 2008 ETP s Board of Directors approved the management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP s distribution amount related to the four months ended December 31, 2007 was $1.125 per Common Unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This distribution was paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

(2) Special SCANA distribution - On June 20, 2006, ETP announced that the Board of Directors of its General Partner declared a special distribution of $0.0325 per Limited Partner Unit related to the proceeds received by ETP in connection with the SCANA litigation

settlement (see Note 11). This distribution was paid on July 14, 2006 to the holders of record of ETP s Common and Class F Units as of the close of business on June 30, 2006.

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On January 26, 2009, ETP announced the declaration of a cash distribution for the fourth quarter ended December 31, 2008 of $0.89375 per Common Unit, or $3.575 annually. ETP paid this distribution on February 13, 2009 to Unitholders of record at the close of business on February 6, 2009.

The total amount of ETP distributions declared during the periods presented in the consolidated financial statements are as follows (all from Available Cash from ETP s operating surplus):

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Limited Partners -				
Common Units	$ 556,295	$ 113,080	$ 366,180	$ 248,237
Class C Units (1)				3,599
Class E Units	12,484	3,121	12,484	12,484
Class F Units				3,232
Class G Units			40,598	
General Partners -				
2% Ownership	17,851	3,582	12,701	6,981
Incentive Distribution Rights	305,072	59,315	203,069	81,722
	$ 891,702	$ 179,098	$ 635,032	$ 356,255

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

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income (AOCI), net of tax:

	December 31, 2008	2007
Net gain on commodity related hedges	$ 8,735	$ 25,497
Net loss on interest rate hedges	(68,896)	(22,439)
Unrealized gains (losses) on available-for-sale securities	(5,983)	483
Minority interests	(1,681)	(14,768)
Total AOCI, net of tax	$ (67,825)	$ (11,227)

8. <u>UNIT-BASED COMPENSATION PLANS</u>:

We recognized non-cash unit-based compensation expense related to the unit-based compensation plans of ETP and ETE of $24.3 million for the year ended December 31, 2008, $8.1 million for the four months ended December 31, 2007, and $10.5 million and $60.0 million for the years ended August 31, 2007 and 2006, respectively. The unit-based compensation expense for August 31, 2006 includes $53.0 million related to the Class B Units issued concurrent with the ETE IPO.

ETE Long-Term Incentive Plan

Concurrently with the IPO during the second quarter of fiscal year 2006, 2,521,570 Class B Units were issued to McReynolds Equity Partners, L.P., the general partner of which is owned and controlled by John W. McReynolds. On March 27, 2007 the Class B Units were converted to Common Units.

In addition, the Board of Directors or the Compensation Committee of the board of directors of the Partnership s general partner (the Compensation Committee) may from time to time grant additional awards to employees, directors and consultants of ETE s general partner and its affiliates who perform services for ETE. The plan provides for the following five types of awards:

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restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The number of additional units that may be delivered pursuant to these awards is limited to 3,000,000 units, excluding the Class B Units discussed above. As of December 31, 2008, 2,931,428 units remain available to be awarded under the plan.

In December 2008, the Compensation Committee granted a total of 65,000 ETE units to employees with vesting over a five-year period at 20% per year. These awards include rights to distributions paid on unvested units. The total grant-date fair value of $1.08 million will be recognized as compensation expense during the vesting period.

On December 22, 2006, the Compensation Committee voted to award each ETE 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 then in office and, automatically on the first day of the fiscal year thereafter, an award of Units equal to $15 thousand divided by the fair market value of ETE Common Units on such date (Annual Director s Grant). Each 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, all awards to a Director Participant shall become fully vested upon a change in control, as defined by the 2004 Unit Plan. As of December 31, 2008, a total of 3,572 restricted units granted to ETE Directors are outstanding under the ETE Long-Term Incentive Plan.

ETP Unit-Based Compensation Plans

ETP has issued equity awards to employees and directors under the following plans:

2008 Long-Term Incentive Plan. On December 16, 2008, ETP Unitholders approved the ETP 2008 Long-Term Incentive Plan (the ETP 2008 Incentive Plan), which provides for awards of options to purchase ETP Common Units, awards of restricted units, awards of phantom units, awards of Common Units, awards of distribution equivalent rights (DERs), awards of Common Unit appreciation rights, and other unit-based awards to employees of ETP, ETP GP (ETP s General Partner), ETP LLC (the Company), a subsidiary or their affiliates, and members of the Company s board of directors, which we refer to as the board of directors. Up to 5,000,000 ETP Common Units may be granted as awards under the ETP 2008 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the ETP 2008 Incentive Plan. The ETP 2008 Incentive Plan is effective until December 16, 2018 or, if earlier, the time which all available units under the ETP 2008 Incentive Plan have been issued to participants or the time of termination of the plan by the board of directors. As of December 31, 2008, a total of 4,776,655 ETP Common Units remain available to be awarded under the ETP 2008 Incentive Plan.

2004 Unit Plan. ETP s Amended and Restated 2004 Unit Award Plan (the ETP 2004 Unit Plan) provides for awards of up to 1,800,000 ETP Common Units and other rights to its 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 ETP 2004 Unit Plan. As of December 31, 2008, 16,847 ETP Common Units were available for future grants under the ETP 2004 Unit Plan.

Restricted Unit Plan. The ETP Restricted Unit Plan provided rights for certain directors and key employees of ETP GP and its affiliates to acquire up to 292,000 ETP Common Units. Following the June 23, 2004 approval of the ETP 2004 Unit Plan at the special meeting of the ETP Unitholders, the ETP Restricted Unit Plan was terminated (except for the obligation to issue ETP Common Units at the time the 16,592 grants previously awarded vest), and no additional grants have been or will be made under the ETP Restricted Unit Plan. No unvested awards remain under this plan. Previously granted awards of 3,667 and 5,000 vested and Common Units were issued during fiscal years 2007 and 2006, respectively.

ETP Employee Grants

Prior to December 2007, substantially all of the awards granted to employees under the ETP 2004 Unit Plan required 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 was 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 with 100% of such one-third vesting if the total return for the ETP 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 the ETP units for such year is in the second quartile as compared to such peer group companies, and 25% of such

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one-third vesting if the total return of the ETP 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 the ETP units for the year plus the aggregate per unit cash distributions received for the year. Non-cash compensation expense is recorded for these ETP awards 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.

In October 2008, the Compensation Committee determined that, of the unit awards subject to the achievement of performance objectives, 25% of the ETP Common Units subject to such awards eligible to vest on September 1, 2007 became vested and 75% of the awards were forfeited based on ETP s performance for the twelve-month period ended August 31, 2008. In October 2008, the Compensation Committee approved a special grant of the new unit awards that entitled each holder to receive a number of ETP Common Units equal to the number of ETP Common Units forfeited as of September 1, 2007, which new unit awards became fully vested on October 15, 2008. These Compensation Committee actions affected all ETP employee unit awards including unit awards granted to ETP s executive officers.

Commencing in December 2007, ETP has also granted restricted unit awards to employees that vest over a specified time period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. Upon vesting, ETP Common Units are issued.

The unit awards under ETP s 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 ETP executive officer. During the year ended December 31, 2008, the Compensation Committee did not accelerate the vesting of any unvested unit awards granted under the ETP 2004 Unit Plan.

In October 2008 and December 2008, the Compensation Committee approved the grant of new unit awards under the ETP 2004 Unit Plan and ETP 2008 Incentive Plan (defined below) to certain of ETP s employees, including certain of its executive officers. All of these unit awards provided for vesting over a five-year period at 20% per year, subject to continued employment through each specified vesting date. These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. We refer to these rights as distribution equivalent rights.

Prior to the October 2008 and December 2008 grants, units were generally awarded without distribution equivalent rights. For such awards, ETP calculated the grant-date fair value based on the market value of the underlying units, 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 distribution yield at that time.

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The following table shows the activity of the ETP awards granted:

	Three-Year Performance Vesting (1)		Five-Year Service Vesting (2)		Other (3)		Total	
	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of August 31, 2005	265,600	$ 19.60					265,600	$ 19.60
Awards granted during fiscal year 2006	183,200	31.08					183,200	31.08
Awards vested during fiscal year 2006	(88,183)	21.65					(88,183)	21.65
Awards forfeited during fiscal year 2006	(2,867)	21.10					(2,867)	21.10
Unvested awards as of August 31, 2006	357,750	24.96					357,750	24.96
Awards granted during fiscal year 2007	458,200	43.75					458,200	43.75
Awards vested during fiscal year 2007	(156,573)	24.23					(156,573)	24.23
Awards forfeited during fiscal year 2007	(101,940)	34.35					(101,940)	34.35
Unvested awards as of August 31, 2007	557,437	39.08					557,437	39.08
Awards granted during the four months ended December 31, 2007			558,750	41.50	158,080	45.82	716,830	42.45
Awards vested during the four months ended December 31, 2007	(56,482)	35.14					(56,482)	35.14
Awards forfeited during the four months ended December 31, 2007	(174,507)	35.10	(500)	41.50	(3,249)	45.82	(178,256)	35.31
Unvested awards as of December 31, 2007	326,448	41.89	558,250	41.50	154,831	45.82	1,039,529	42.27
Awards granted during calendar year 2008			833,545	34.28	101,982	30.29	935,527	33.84
Awards vested during calendar year 2008	(42,337)	41.39	(119,030)	47.93	(239,240)	39.29	(400,607)	42.08
Awards forfeited during calendar year 2008	(133,259)	39.72	(67,335)	41.54	(8,597)	45.82	(209,191)	40.55
Unvested awards as of December 31, 2008	150,852	43.96	1,205,430	35.87	8,976	43.48	1,365,258	$ 36.81

(1) Includes awards subject to performance objectives, as discussed above.
(2) Includes awards for which vesting is subject to continued employment, as discussed above.
(3) Includes special grants described above and awards issued with other vesting conditions.

ETP recognized non-cash unit-based compensation expense related to employee grants under its unit-based compensation plans of 23.3 million for the year ended December 31, 2008, $8.0 million for the four months ended December 31, 2007, and $10.3 million and $6.8 million for the years ended August 31, 2007 and 2006, respectively. The total expected non-cash compensation expense to be recognized related to the unvested employee awards as of December 31, 2008 was:

Year Ending December 31:	Three-Year Performance Vesting	Five-Year Service Vesting	Other	Total
2009	1,008	18,229	33	19,270
2010		10,259		10,259
2011		6,018		6,018
2012		3,142		3,142
2013		1,011		1,011

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ETP Director Grants

The ETP 2008 Incentive Plan provides for annual grants of ETP Common Units to non-employee directors of its General Partner equal to $50 thousand divided by the fair market value of ETP Common Units as of each anniversary date of December 19, 2008, the date of the adoption of the ETP 2008 Incentive Plan.

Under the ETP 2004 Unit Plan, each director who was 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 was elected or appointed to the Board for the first time automatically received, 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). In addition, each September 1 each Director Participant who was in office on such September 1, automatically received an award of units equal to $25 thousand divided by the fair market value of an ETP 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 vested 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 became fully vested upon a change in control, as defined by the Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which had not yet vested on the date a Director Participant ceased to be a director vested on such terms as determined by the Compensation Committee.

The following table shows the activity of the ETP Director Awards granted:

	Number of Units	Weighted Average Fair Value Per Unit
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 forfieted 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 forfieted during fiscal year 2007		
Unvested awards as of August 31, 2007	12,166	27.63
Annual Director Grants awarded during four months ended December 31, 2007	2,880	45.87
Awards vested during the four months ended December 31, 2007	(8,118)	23.14
Unvested awards as of December 31, 2007	6,928	40.47
Annual Director Grants awarded in calendar year 2008	4,470	38.45
Awards vested during calendar year 2008	(4,088)	37.81
Unvested awards as of December 31, 2008	7,310	40.72

ETP recognized non-cash compensation expense related to director grants under its unit-based compensation plans of 0.2 million for the year ended December 31, 2008, $0.1 million for the four months ended December 31, 2007, and $0.2 million and $0.2 million for the years ended August 31, 2007 and 2006, respectively. The total expected non-cash compensation expense to be recognized related to the unvested ETP Director Awards as of December 31, 2008 was:

Years Ending December 31	
2009	$ 122
2010	44
2011	10

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Related Party Awards

During 2007, a partnership (McReynolds Energy Partners, L.P.), 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 ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. 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 fair value of the ETE units awarded the ETP employees assuming no forfeitures.

Rights related to 55,000 ETE units vested in December 2007, rights related to 60,000 ETE units vested in March 2008, rights related to 20,000 ETE units vested in June 2008, and rights related to 55,000 ETE units vested in December 2008. In June 2008, rights related to 240,000 ETE units were forfeited due to the resignation of an officer of ETP.

In July 2008, rights related to 240,000 ETE units were awarded to ETP s current chief financial officer. In December 2008, rights related to 210,000 ETE units were awarded to ETP s president and chief operating officer. These awards have similar terms to those discussed above, including vesting over five years at 20% per year. As discussed above, none of the costs related to these awards will be paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these unit awards are viewed as compensation to these recipients for financial reporting purposes, the Compensation Committee considered and approved these unit awards.

As of December 31, 2008, rights related to 695,000 unvested ETE units remained outstanding. For the year ended December 31, 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized non-cash compensation expense, net of forfeitures, of $3.5 million, $3.6 million, and $5.2 million, respectively, as a result of these awards. As these units were outstanding prior to these awards, these 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. As of December 31, 2008, we expect to recognize non-cash compensation expense as follows in future periods related to these awards:

Years Ending December 31:	
2009	$ 6,395
2010	3,663
2011	2,034
2012	847
2013	277

In October 2008, related party awards of 50,000 vested ETE units were granted, resulting in immediate recognition of non-cash compensation expense of $0.76 million.

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9. INCOME TAXES:

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

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Current provision:				
Federal	$ (180)	$ 2,990	$ 7,896	$ 27,640
State	12,241	5,831	10,432	1,987
Total	12,061	8,821	18,328	29,627
Deferred provision:				
Federal	(8,531)	516	(7,494)	(6,227)
State	278	612	557	(385)
Total	(8,253)	1,128	(6,937)	(6,612)
Total Tax Provision	$ 3,808	$ 9,949	$ 11,391	$ 23,015

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 December 31, 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $10.5 million, $3.9 million and $6.9 million, respectively. There was no comparable state tax expense for the fiscal year ended August 31, 2006.

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:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	1.59%	2.57%	1.25%	3.10%
Earnings not subject to tax at the Partnership level	(36.03)%	(32.41)%	(34.23)%	(32.80)%
Effective tax rate	0.56%	5.16%	2.02%	5.30%

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:

	December 31, 2008	December 31, 2007
Property, plant and equipment	$ 199,306	$ 199,809
Other, net	(3,846)	554
Total deferred tax liability	$ 195,460	$ 200,363

10. MAJOR CUSTOMERS AND SUPPLIERS:

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 accounted for 10% or more of our consolidated revenue.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Propane segments:				
Unaffiliated				
M.P. Oils, Ltd.	14.9%	14.2%	20.7%	22.0%
Targa Liquids	15.0%	15.9%	22.6%	18.2%
Affiliated				
Enterprise	50.7%	50.6%	22.1%	27.0%

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% of our combined total propane purchases during fiscal year 2006. 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 11).

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 90.0 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.

11. 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. In April 2007, the FERC approved a Stipulation and Agreement of Settlement (Stipulation and Agreement) that resolved primary components of the rate case. 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 the 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. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (Order). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. On December 17, 2007, two parties filed requests for rehearing of the Order and on December 20, 2007, one party filed a motion to stay the Order. On February 21, 2008, the FERC reaffirmed its decision in the Order; thus, Transwestern notified customers of the commencement of construction in January 2008. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was completed in February 2009.

As discussed in Note 3, certain regulatory approvals are still pending with respect to the expansion and interim service of MEP.

Guarantees

On February 29, 2008, MEP entered into a credit agreement that provides for a $1.40 billion senior revolving credit facility (the MEP Facility). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP 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 MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets. The MEP Facility is syndicated among multiple financial institutions; the Royal Bank of Scotland PLC is the administrative agent. Among the lending banks that make up the syndicate of financial institutions for the MEP Facility, affiliates of Lehman Brothers had committed to approximately $100.0 million of the $1.40 billion facility. As a result of the Lehman Brothers bankruptcy in 2008, the MEP Facility has effectively been reduced by the amount of the Lehman Brothers affiliates commitment. However, the MEP Facility is not in default, and the commitments of the other lending banks remain unchanged.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP Facility for previous advances ETP made to MEP. As of December 31, 2008, MEP had $837.5 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $418.8 million and $16.7 million, respectively, as of December 31, 2008. The weighted average interest rate on the total amount outstanding as of December 31, 2008 was 3.1271%. The total amount available under the MEP Facility was $429.2 million as of December 31, 2008.

MEP previously had a $197.0 million reimbursement agreement under which MEP could issue letters of credit. This reimbursement agreement expired in and there are no longer any letters of credit outstanding.

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 has been included in operating expenses in the accompanying statements of operations and totaled approximately $17.2 million, $9.4 million, $33.2 million and $18.0 million for the year ended December 31, 2008, the four months ended December 31, 2007 and the fiscal years ended August 31, 2007 and 2006, respectively. Future minimum lease commitments for such leases are:

2009	$ 21,041
2010	19,854
2011	18,644
2012	16,573
2013	14,426
Thereafter	224,110

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 488,097 MMBtu/d. Long-term contracts require delivery of up to 15,878 MMBtu/d and extend through July 2018.

During fiscal year 2007, 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 located along the Texas gulf coast region. Under the terms of the 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.

We have an eight year transportation agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 100,000 MMBtu per year. We also have 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 December 31, 2008, August 31, 2007 and 2006, 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 $10.7 million, $10.8 million and $13.4 million in additional fees during the second quarter of 2008 and the third fiscal quarters of 2007 and 2006, 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.

We also have two long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts 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 14) 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.

In connection with the sale of ETP s investment in M-P Energy in October 2007, ETP executed a seven-year propane purchase agreement for approximately 90.0 million gallons per year at market prices plus a nominal fee.

ETP previously had a percentage guaranty with a financial institution whereby it would be liable for its 50% of any defaulted payments not made by MEP, plus interest. The reimbursable agreement which had a commitment up to $197.0 million expired 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 FERC issued to ETP an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that ETP violated FERC rules and regulations. The FERC has alleged that ETP 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 occasions from December 2003 through August 2005, in order to benefit financially from ETP s commodities derivatives positions and from certain of its index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods

ETP violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the Natural Gas Act (NGA). ETP 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 ETP manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. ETP s Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to the 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. On October 29, 2008, ETP moved for summary disposition of the claim that Oasis unduly discriminated against non-affiliated shippers and unduly preferred affiliated shippers. The presiding administrative law judge granted this motion on November 18, 2008, holding that FERC Staff had failed to make a prima facie case in support of this claim. This ruling, if allowed to stand, significantly narrows the FERC s Oasis-related claims in the Order and Notice proceeding. The FERC also seeks to revoke, for a period of 12 months, ETP s blanket marketing authority for sales of natural gas in interstate commerce at market-based prices, which activity is expected to account for approximately 1.0% of ETP s operating income for our 2008 year. If the FERC is successful in revoking ETP s blanket marketing authority, ETP s sales of natural gas at market-based prices would be limited to sales to retail customers (such as utilities and other end-users) and sales from its own production, and any other sales of natural gas by ETP would be required to be made at contract prices that would be subject to individual FERC approval.

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 has taken the position that, once it receives ETP s 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. On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed the FERC Enforcement Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. 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. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The Enforcement Staff also recommended that FERC issue an order assessing the $15.5 million portion of the above-referenced penalty against ETP with respect to the allegations related to ETP s Oasis pipeline and that the Oasis-related penalty assessment, if not paid, then be referred by the FERC to a federal district court for de novo review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis business operations and refunds to certain Oasis customers as previously proposed in the Order and Notice. Finally, the Enforcement Staff recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005, for November 2005 monthly deliveries, a period not previously covered by FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month. If the FERC pursues the claims related to this additional month, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $200.0 million. On March 31, 2008, we responded to the Enforcement Staff s brief. On May 15, 2008, the FERC ordered hearings to be conducted by FERC administrative law judge s with respect to the FERC's Oasis claims and market manipulation claims. The hearing related to the Oasis claims was scheduled to commence in December 2008 with the administrative law judge s initial decision due by May 11, 2009, however, as discussed below, ETP entered into a settlement agreement with FERC Enforcement Staff and that agreement was approved by the FERC in its entirety and without modification on February 27, 2009. The hearing related to the market manipulation claims is now scheduled to commence in June 2009 with the administrative law judge s initial decision due by December 3, 2009. The FERC also ordered that, following the completion of the hearings, the administrative law judges make initial findings with respect to whether we engaged in market manipulation in violation of the NGA and FERC regulations and whether Oasis violated the NGPA and FERC regulations. The FERC reserved for itself the issues of possible civil penalties, revocation of our blanket market certificate, the method by which we and Oasis would disgorge any unjust profits and whether any conditions should be placed on Oasis s Section 311 authorization. Following the issuance of each of the administrative law judge s initial decisions, the FERC would then issue an order with respect to each of these matters. On May 23, 2008, we requested rehearing and stay of the FERC's May 15, 2008 order establishing hearing, and we renewed those requests on June 26, 2008. On August 7, 2008, FERC denied rehearing of its May 15, 2008 order. On August 8, 2008, we filed a petition with the U.S. Court of Appeals for the Fifth Circuit to review and set aside FERC s May 15 and August 7, 2008 orders on the grounds that we are entitled to adjudicate FERC s claims in federal district court pursuant to the NGA and the NGPA. On August 28, 2008, we filed an amended petition seeking review of the Order and Notice and the December 20, 2007 order denying rehearing.

On November 18, 2008, the administrative law judge presiding over the Oasis claims granted ETP s motion for summary disposition of the claim that Oasis unduly discriminated in favor of affiliates regarding the provision of Section 311(a)(2) interstate transportation service. ETP subsequently entered into an agreement with the Enforcement Staff to settle all of the claims related to Oasis. On January 5, 2009, this agreement was submitted under seal to FERC by the presiding administrative law judge, for FERC s approval as an uncontested settlement of all Oasis claims. On February 27, 2009, the settlement agreement was approved by the FERC in its entirety and without modification and the terms of the settlement were made public. If no person seeks rehearing of the order approving the settlement within 30 days of such order, the FERC s order will become final and non-appealable. We do not believe the Oasis settlement, as approved by the FERC, will have a material adverse effect on our business, financial condition or results of operations.

It is ETP s position that its trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and ETP intends 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 holds substantial enforcement authority. At this time, neither we nor ETP is able to predict the final outcome of these matters.

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 (the CEA) by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, ETP entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, ETP agreed to pay the CFTC $10.0 million and the CFTC agreed to release ETP and its affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that ETP is permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the CEA. By consenting to the entry of the Consent Order, ETP neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations in March 2008.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETP for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETP for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETP contains an additional allegation that we and ETP transported gas in a manner that favored our and ETP s affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have moved to compel arbitration and/or contested subject-matter jurisdiction in some of these cases. Once such case currently is on appeal before the Texas Supreme Court on, among other things, the issue of whether the dispute is arbitrable.

We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producers/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The claimants have filed a notice of appeal.

A consolidated class action complaint has been filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the New York Mercantile Exchange, or NYMEX, in violation of the CEA. It is further alleged that during the class period December 29, 2003 to December 31, 2005, ETP had the market power to manipulate index prices, and that it used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit its natural gas physical and financial trading positions and that ETP intentionally submitted price and volume trade information to trade publications. This complaint also alleges that ETP violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by ETP manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action, and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, ETP filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, ETP filed a motion to dismiss the complaint. On June 19, 2008 the plaintiffs filed a response opposing ETP s motion to dismiss. ETP filed a reply in support of its motion on July 9, 2008.

On March 17, 2008, a second class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period ETP exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit from its own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, ETP filed a motion to dismiss this complaint. On July 2, 2008 the plaintiffs filed a response opposing ETP s motion to dismiss. ETP filed a reply in support of our motion on August 18, 2008.

We are expensing the legal fees, consultants fees and other 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 to service our indebtedness 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 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 Tariff, 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 the 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. 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 filed on or about July 31, 2007. Appellee s opposition brief was filed on or about November 21, 2007. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg s reply brief was filed in June 2008 and the hearing on all briefs was held in September 2008, with a ruling expected in the near future. 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.

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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. The matter has been fully resolved as of September 2008 and Transwestern has obtained ROW grants that are effective through December 27, 2022.

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 (approximately $1.00 billion in the aggregate). 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. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel Storage Facility. AEP is appealing the court decision. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

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. 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 December 31, 2008 and 2007, an accrual of $20.8 million and $30.5 million, 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 contamination by polychlorinated biphenyls (PCBs) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $9.1 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern continues to incur certain costs related to PCBs that could migrate through its pipelines 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 $0.8 million for the period since acquisition. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at December 31, 2008. 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 the EPA 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.

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 us, 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.

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.

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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 December 31, 2008 and 2007, an accrual on an undiscounted basis of $13.3 million and $15.7 million, 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.

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 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. Through December 31, 2008, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2009. Through December 31, 2008, a total of $16.4 million of capital costs and $12.7 million of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through December 31, 2008, a total of $6.9 million of capital costs and $0.4 million of operating and maintenance costs have been incurred for pipeline integrity costs 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.

12. 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 derivative 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.

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We have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. 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 and clearing brokers of $78.2 million and $42.2 million as of December 31, 2008 and 2007, respectively, reflected as deposits paid to vendors on our consolidated balance sheets.

We disclose the non-exchange traded financial derivative instruments as price risk assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated contract date. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendor on the 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 (AOCI) until the underlying hedged transaction is recorded in earnings. Any ineffective portion of a cash flow hedge s change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction is recorded in earnings, 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 financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded each period in cost of products sold in the consolidated statements of operations. We reclassified into earnings gains of $34.5 million, $162.5 million, $73.2 million and $17.1 million for the years ended December 31, 2008, August 31, 2007 and 2006 and the four months ended December 31, 2007, respectively, related to commodity financial instruments that were previously reported in AOCI.

We expect gains of $8.8 million related to commodity derivatives to be reclassified into earnings over the next twelve months related to income currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

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. As of December 31, 2008, these contracts have settled and are no longer reflected on our consolidated balance sheet.

Trading Activities

Due to a high level of market volatility as well as other business considerations, as of July 2008 we determined that we will no longer engage in the trading of financial derivative instruments that are not offset by physical positions. As a result, we will no longer have any material exposure to market risk from such derivative positions. The derivative contracts that were previously entered into for trading purposes are recognized in 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. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the year ended December 31, 2008, net gains of approximately $2.2 million for the fiscal year ended August 31, 2007, net gains of $20.1 million for the year ended August 31, 2006, and net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007.

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The following table details the outstanding commodity-related derivatives:

December 31, 2008

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset
Mark to Market Derivatives				
Basis Swaps IFERC/NYMEX	Gas	15,720,000	2009-2011	$ 3,125
Swing Swaps IFERC	Gas	(58,045,000)	2009	(118)
Fixed Swaps/Futures	Gas	(20,880,000)	2009-2010	97,498
Forwards/Swaps - in Gallons	Propane	47,313,002	2009	(42,288)
Cash Flow Hedging Derivatives				
Basis Swaps IFERC/NYMEX	Gas	(9,085,000)	2009	$ 3,268
Fixed Swaps/Futures	Gas	(9,085,000)	2009	6,691

December 31, 2007

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,732,500	2008-2009	$ (2,767)
Swing Swaps IFERC	Gas	(4,640,000)	2008	(1,515)
Fixed Swaps/Futures	Gas	(26,987,500)	2008-2009	14,230
Forward Physical Contracts	Gas	(17,847,140)	2008	(1,063)
Options	Gas	(670,000)	2008	(161)
Forward/Swaps - in Gallons	Propane	9,282,000	2008	3,319
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(18,362,500)	2008	$ 2,298
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(11,255,000)	2008-2009	$ (1,262)
Fixed Swaps/Futures	Gas	(13,120,000)	2008-2009	26,913

We 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, fluctuating commodity prices can impact our financial results and financial position, either favorably or unfavorably.

During certain periods presented in these consolidated financial statements, we have discontinued the application of hedge accounting in connection with certain derivative financial instruments that had previously been qualified and designated as cash flow hedges related to forecasted sales of natural gas stored in our 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 through March 2007 and 2006, and unfavorable market conditions in 2008. 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 of the discontinued application of hedge accounting, we recognized previously deferred unrealized losses of

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$10.3 million, unrealized gains of $9.2 million, unrealized gains of $37.2 million and unrealized gains of $84.7 million, which are included in the reclassification into earnings from AOCI during the year ended December 31, 2008, the four months ended December 31, 2007 and the fiscal years ended August 31, 2007 and 2006, respectively. We recorded these amounts in cost of products sold in our 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. Since fiscal 2007, gains and losses on interest rate derivatives that are not cash flow hedges are classified in other income. Prior to fiscal 2007, such gains or losses were reported in interest expense.

The following table represents interest rate swap derivatives:

				Fair Value Liability as of	
Term	**Notional Amount**	**Type**	**SFAS 133 Hedge**	**December 31, 2008**	**December 31, 2007**
March 2009	$ 125,000	Pay Fixed 5.14%	No	$ 1,134	$ 1,530
		Receive Float			
May 2016	300,000	Pay Fixed 5.2%	No		
		Receive Float		50,711	15,870
November 2012	700,000	Pay Fixed 4.84%	Yes		
		Receive Float		71,042	23,281
November 2012	500,000	Pay Fixed 4.57%	No		
		Receive Float		47,410	16,020
		Pay Fixed 3.99%			
December 2009	500,000	Receive Float	No	50,509	

We reclassified into earnings losses of $11.3 million and gains of $0.7 million, $2.1 million, and $1.4 million for the year ended December 31, 2008, the four months ended December 31, 2007 and the years ended August 31, 2007 and 2006, respectively, related to interest rate swaps that were previously reported in AOCI. We expect losses of $24.7 million to be reclassified into earnings over the next twelve months related to income on interest rate financial instruments currently reported in AOCI. The amount ultimately realized, however, will differ as interest rates change.

The following table represents pre-tax balances in AOCI related to interest rate swaps before income taxes and the allocation to minority interest:

				Accumulated Other Comprehensive Income (Loss) as of	
Date Settled	**Term**	**Notional Amount**	**Type**	**December 31, 2008**	**December 31, 2007**
Quarterly through maturity	2012	$ 700,000	Pay Fixed 4.84%	$ (69,057)	$ (23,365)
			Receive Float		
April 2007	2014	400,000	LIBOR	(10,622)	(11,135)
			Forward Starting		
June 2006	2016	200,000	Treasury Lock	11,017	12,210
January 2005	2017	100,000	Treasury Lock	(234)	(269)
				$ (68,896)	$ (22,559)

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Summary of Derivative Gains and Losses

The following represents gains (losses) on derivative activity recognized in net income:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Commodity-related				
Unrealized non-trading gains related to commodity-related derivatives recognized in cost of products sold, excluding ineffectiveness	$ 46,333	$ 4,934	$ 10,709	$ 9,630
Ineffective portion of cash flow hedge derivatives recognized in cost of products sold	(8,347)	8,472	183	16,701
Realized non-trading gains related to commodity-related derivatives included in cost of products sold	9,018	13,625	184,726	138,629
Unrealized trading losses recognized in revenues	(2,458)	(205)	(19,393)	(25,255)
Realized trading gains (losses) recognized in revenues	(25,825)	(2,094)	21,555	45,370
Interest rate swaps				
Unrealized losses on non-hedged interest rate swaps included in other income and interest expense	$ (118,415)	$ (30,059)	$ (4,020)	$ (128)
Ineffective portion of cash flow derivatives included in interest expense		(2)	(1,813)	842
Realized gains (losses) on interest rate swaps included in interest expense and other income	(21,357)	2,097	38,810	616

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.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

13. <u>RETIREMENT BENEFITS</u>:

ETP sponsors 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 ETP s 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 $9.7 million, $2.6 million, $8.5 million and $5.7 million to the 401(k) savings plan for the year ended December 31, 2008, the four months ended December 31, 2007, and the fiscal years ended August 31, 2007 and 2006, respectively.

14. <u>RELATED PARTY TRANSACTIONS</u>:

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 acquired a 34.9% non-controlling equity interest in our General Partner, LE GP, L.L.C. (LE GP). Cash consideration paid by Enterprise totaled approximately $1.65 billion, reflecting a purchase price of $42.00 per ETE Common Unit. As a result of these transactions, EPE and its subsidiaries are considered related parties.

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We made the following sales to and purchases from affiliates of Enterprise:

Enterprise Transactions	Product	Volumes (in thousands)	Dollars
Calendar Year Ended December 31, 2008			
Propane Operations -			
Sales	Propane - gallons	13,230	$ 19,769
Purchases	Propane - gallons	318,982	491,367
Natural Gas Operations -			
Sales	NGLs - gallons	58,361	96,974
	Natural Gas - MMBtu	6,256	52,205
	Fees		5,093
Purchases	Natural Gas Imbalances - MMBtu	3,488	(6,485)
	Natural Gas - MMBtu	13,457	120,837
	Fees		876
Four Months Ended December 31, 2007			
Propane Operations -			
Purchases	Propane - gallons	112,961	$ 175,839
Natural Gas Operations -			
Sales	NGLs - gallons	3,240	4,726
	Natural Gas - MMBtu	2,036	11,452
	Fees		610
Purchases	Natural Gas Imbalances - MMBtu	313	(911)
	Natural Gas - MMBtu	3,577	23,341
	Fees		311
Period from May 7, 2007 (the date Enterprise became an affiliate) to August 31, 2007			
Propane Operations -			
Purchases	Propane-gallons	45,490	$ 55,938
Natural Gas Operations -			
Sales	NGLs - gallons	464	648
	Natural Gas - MMBtu	1,495	9,768
Purchases	Natural Gas Imbalances - MMBtu	3,120	22,677
	Natural Gas - MMBtu	1,541	7,501

Titan has a long-term purchase contract to purchase substantially all of its propane requirements, and as of December 31, 2008 had forward mark to market derivatives for approximately 45.2 million gallons of propane at a fair value liability of $40.1 million with Enterprise. Additionally, HOLP has a monthly storage contract with TEPPCO Partners, L.P. (an affiliate of Enterprise) for approximately $0.3 million 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. Our propane operations routinely buy and sell product with Enterprise. The following table summarizes the related party balances with Enterprise on our consolidated balance sheets:

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	December 31, 2008	December 31, 2007
Natural Gas Operations:		
Accounts receivable	$ 11,558	$ 9,770
Accounts payable	567	6,840
Imbalance payable	(547)	6,218
Propane Operations:		
Accounts receivable	$ 111	$ 3,396
Accounts payable	33,308	41,939

Accounts receivable from related companies excluding Enterprise consist of the following:

	December 31, 2008	December 31, 2007
LE GP	$	$ 174
MEP	2,805	743
Energy Transfer Technologies, Ltd.	16	922
McReynolds Energy	202	
Others	450	3,065
Total accounts receivable from related companies excluding Enterprise	$ 3,473	$ 4,904

As of December 31, 2007, we had advances due from a propane joint venture of $18.2 million, which are included in advances to and investment in affiliates on our consolidated balance sheet. Because we acquired 100% of this joint venture in 2008, there was no comparable balance due at December 31, 2008.

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 year ended December 31, 2008, the four months ended December 31, 2007 and the fiscal years ended August 31, 2007 and 2006, we made payments totaling $9.4 million, $0.8 million, $2.4 million and $2.9 million, 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 December 31, 2008 and 2007, accounts receivable from ETG related to compressor leases were $0.02 million and $0.9 million, respectively.

The Partnership also pays ETP an annual administrative fee of $0.5 million for the provision of various general and administrative services for ETE s benefit. Fees paid under this agreement during the year ended December 31, 2008 were nominal.

In fiscal year 2006, 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 $0.7 million from an entity that includes one of the General Partner s directors.

The Chief Executive Officer (CEO) of ETP s General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. We recorded non-cash compensation expense and an offsetting capital contribution of $1.3 million ($0.5 million in salary and $0.8 million in accrued bonuses) for the year ended December 31, 2008 as an estimate of the reasonable compensation level for the CEO position.

See Notes 3 and 7 for discussion of other related party transactions with ETP and ETI.

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15. REPORTABLE SEGMENTS:

Our financial statements reflect four reportable segments which conduct their business exclusively in the United States of America, as follows:

- natural gas operations:
  - midstream
  - intrastate transportation and storage
  - interstate transportation
- retail propane operations

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. 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.

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 years 2008 and 2007 to fiscal year 2006 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. 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.

See Note 1, "Business Operations" for a 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") which is based on factors such as respective segments' gross margins, employee costs, and property and equipment.

The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the periods presented are as follows:

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	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Costs allocated from ETP to Operating Partnerships:			
Midstream and intrastate transportation operations	$ 19,834	$ 6,761	$ 11,357
Interstate operations	5,750	2,613	4,388
Propane operations	12,664	5,992	10,067
Total	$ 38,248	$ 15,366	$ 25,812
Costs allocated from Operating Partnerships to ETP:			
Midstream and intrastate transportation operations	$ 10,649	$ 2,440	$ 5,221
Propane operations	2,428	850	2,187
Total	$ 13,077	$ 3,290	$ 7,408

The following table presents the financial information by segment for the following periods:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31,	
			2007	2006
Revenues:				
Midstream	$ 5,342,393	$ 1,166,313	$ 2,853,496	$ 4,223,544
Eliminations	(3,568,065)	(664,522)	(1,562,199)	(2,359,256)
Intrastate transportation and storage	5,634,604	1,254,401	3,915,932	5,013,224
Interstate transportation (see Note 3)	244,224	76,000	178,663	
Retail propane and other retail propane related	1,624,010	511,258	1,284,867	879,556
All other	16,201	5,892	121,278	102,028
Total revenues	$ 9,293,367	$ 2,349,342	$ 6,792,037	$ 7,859,096
Cost of Products Sold:				
Midstream	$ 4,986,495	$ 1,043,191	$ 2,632,187	$ 4,000,461
Eliminations	(3,568,065)	(664,522)	(1,562,199)	(2,359,256)
Intrastate transportation and storage	4,467,552	964,568	3,137,712	4,322,217
Retail propane and other retail propane related	1,038,722	325,158	759,634	515,418
All other	13,376	5,259	110,872	89,476
Total cost of products sold	$ 6,938,080	$ 1,673,654	$ 5,078,206	$ 6,568,316
Depreciation and Amortization:				
Midstream	$ 63,287	$ 14,943	$ 27,331	$ 19,687
Intrastate transportation and storage	92,979	23,429	64,423	50,755
Interstate transportation	37,790	12,305	27,972	
Retail propane and other retail propane related	79,717	24,537	70,833	58,036
All other	599	192	824	1,158
Total depreciation and amortization	$ 274,372	$ 75,406	$ 191,383	$ 129,636

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	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Operating Income (Loss):				
Midstream	$ 162,471	$ 71,853	$ 119,233	$ 147,564
Intrastate transportation and storage	710,070	169,361	479,820	422,420
Interstate transportation	124,676	29,657	95,650	
Retail propane and other retail propane related	114,564	46,747	124,263	76,055
All other	(2,032)	(796)	1,735	1,899
Selling general and administrative expenses not allocated to segments	(10,846)	(171)	(11,365)	(72,398)
Total operating income	$ 1,098,903	$ 316,651	$ 809,336	$ 575,540
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (357,541)	$ (103,375)	$ (279,986)	$ (150,646)
Loss on extinguishment of debt				(5,060)
Equity in earnings (losses) of affiliates	(165)	(94)	5,161	(479)
Gain (loss) on disposal of assets	(1,303)	14,310	(6,310)	851
Gains (losses) on non-hedged interest rate derivatives	(128,423)	(28,683)	29,081	
Allowance for equity funds used during construction	63,976	7,276	4,948	
Other, net	8,115	(13,327)	1,129	13,701
Income tax expense	(3,808)	(9,949)	(11,391)	(23,015)
Minority interests	(304,710)	(90,132)	(232,608)	(303,752)
	(723,859)	(223,974)	(489,976)	(468,400)
Net Income	$ 375,044	$ 92,677	$ 319,360	$ 107,140

	December 31, 2008	December 31, 2007
Total Assets:		
Midstream	$ 1,674,028	$ 1,444,446
Intrastate transportation and storage	4,911,770	4,254,514
Interstate transportation	2,487,078	1,834,941
Retail propane and other retail propane related	1,810,953	1,778,426
All other	186,073	149,767
Total	$ 11,069,902	$ 9,462,094

	Year Ended December 31, 2008	Four Months Ended December 31, 2007
Additions to Property, Plant and Equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Midstream	$ 267,900	$ 414,722
Intrastate transportation and storage	993,886	320,965
Interstate transportation	720,186	167,343
Retail propane and other retail propane related	130,358	47,553

All other	3,072	953
Total	$ 2,115,402	$ 951,536

16. <u>QUARTERLY FINANCIAL DATA (UNAUDITED)</u>:

Summarized unaudited quarterly financial data is presented below. 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

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the operations of ET Fuel 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				
	March 3 1	June 30	September 30	December 31	Total Year
Fiscal 2008:					
Revenues	$ 2,639,245	$ 2,653,351	$ 2,206,090	$ 1,794,681	$ 9,293,367
Gross Profit	659,527	529,279	572,636	593,845	2,355,287
Operating income	367,929	221,940	256,264	252,770	1,098,903
Net income	126,705	120,394	105,379	22,566	375,044
Limited Partners interest in net income	126,313	120,021	105,053	22,496	373,883
Basic net income per limited partner unit	$ 0.57	$ 0.54	$ 0.47	$ 0.10	$ 1.68
Diluted net income per limited partner unit	$ 0.57	$ 0.54	$ 0.47	$ 0.10	$ 1.68

	Four Months Ended December 31
Transition Period:	
Revenues	$ 2,349,342
Gross Profit	675,688
Operating income	316,651
Net income	92,677
Limited Partners interest in net income	92,390
Basic net income per limited partner unit	$ 0.41
Diluted net income per limited partner unit	$ 0.41

	Quarter Ended				
	November 30	February 28	May 31	August 31	Total Year
Fiscal 2007:					
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	103,088	351,851	187,259	167,138	809,336
Net income	31,041	147,356	89,093	51,870	319,360
Limited Partners interest in net income	30,896	146,889	88,817	51,710	318,312
Basic net income per limited partner unit	$ 0.20	$ 0.67	$ 0.40	$ 0.23	$ 1.56
Diluted net income per limited partner unit	$ 0.20	$ 0.67	$ 0.40	$ 0.23	$ 1.55

17. SUPPLEMENTAL INFORMATION:

Following are the financial statements of the Parent Company which are included to provide additional information with respect to the Parent Company's financial position, results of operations and cash flows on a stand-alone basis:

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BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 62	$ 42
Accounts receivable from related companies	459	11,586
Prepaid expenses and other	163	66
Total current assets	684	11,694
ADVANCES TO AND INVESTMENT IN AFFILIATES	1,662,074	1,607,658
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	8,581	11,588
Total assets	$ 1,671,339	$ 1,630,940
LIABILITIES AND PARTNERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable	$ 798	$ 728
Accounts payable to affiliates	3,034	1,574
Accrued interest	9,222	15,671
Accrued and other current liabilities	912	564
Income taxes payable		252
Price risk management liabilities	47,453	9,189
Total current liabilities	61,419	27,978
LONG-TERM DEBT, less current maturities	1,571,642	1,572,643
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	121,710	45,982
COMMITMENTS AND CONTINGENCIES		
	1,754,771	1,646,603
PARTNERS DEFICIT:		
General Partner	155	192
Limited Partner Common Unitholders (222,829,956 units authorized, issued and outstanding at December 31, 2008 and 2007	(15,762)	(4,628)
Accumulated other comprehensive loss	(67,825)	(11,227)
Total partners deficit	(83,432)	(15,663)
Total liabilities and partners capital (deficit)	$ 1,671,339	$ 1,630,940

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STATEMENTS OF OPERATIONS

(in thousands)

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ (6,453)	$ (2,875)	$ (8,496)	$ (55,374)
OTHER INCOME (EXPENSE):				
Interest expense	(91,822)	(37,071)	(104,405)	(36,773)
Equity in earnings of affiliates	551,835	168,547	435,247	204,987
Loss on extinguishment of debt				(5,060)
Losses on non-hedged interest rate derivatives	(77,435)	(27,670)	(1,952)	
Other, net	(1,056)	(8,128)	(405)	(638)
INCOME BEFORE INCOME TAXES	375,069	92,803	319,989	107,142
Income tax expense	25	126	629	2
NET INCOME	375,044	92,677	319,360	107,140
GENERAL PARTNER'S INTEREST IN NET INCOME	1,161	287	1,048	609
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 373,883	$ 92,390	$ 318,312	$ 106,531

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STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 436,819	$ 77,360	$ 239,777	$ 110,554
CASH FLOWS FROM INVESTING ACTIVITIES:				
Advances to and investment in subsidiaries			(1,200,000)	(135,088)
Net cash used in investing activities			(1,200,000)	(135,088)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	190,533	1,255	1,252,662	666,058
Principal payments on debt	(191,464)		(367,529)	(649,575)
Equity offerings			372,434	473,978
Redemption of Common Units in IPO				(131,620)
Repurchase of Common Units				(237,817)
Cash distributions to Partners	(435,868)	(87,174)	(276,997)	(101,259)
Debt issuance costs			(11,881)	(3,623)
Net cash provided by (used for) financing activities	(436,799)	(85,919)	968,689	16,142
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	20	(8,559)	8,466	(8,392)
CASH AND CASH EQUIVALENTS, beginning of period	42	8,601	135	8,527
CASH AND CASH EQUIVALENTS, end of period	$ 62	$ 42	$ 8,601	$ 135

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18. COMPARATIVE INFORMATION FOR THE FOUR MONTHS ENDED DECEMBER 31, 2007:

The unaudited financial information for the four month period ended December 31, 2006, contained herein is presented for comparative purposes only 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 EQUITY, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Four Months Ended December 31, 2007	2006
REVENUES:		
Natural gas operations	$ 1,832,192	$ 1,668,667
Retail propane	471,494	409,821
Other	45,656	83,978
Total revenues	2,349,342	2,162,466
COSTS AND EXPENSES:		
Cost of products sold natural gas operations	1,343,237	1,382,473
Cost of products sold retail propane	315,698	256,994
Cost of products sold other	14,719	50,376
Operating expenses	221,757	173,365
Depreciation and amortization	75,406	52,840
Selling, general and administrative	61,874	43,602
Total costs and expenses	2,032,691	1,959,650
OPERATING INCOME	316,651	202,816
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(103,375)	(82,979)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other income (expense), net	(34,734)	2,248
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	192,758	129,040
Income tax expense	9,949	2,155
INCOME BEFORE MINORITY INTERESTS	182,809	126,885
Minority interests	(90,132)	(50,204)
NET INCOME	92,677	76,681
GENERAL PARTNER'S INTEREST IN NET INCOME	287	290
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 92,390	$ 76,391
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.41	$ 0.45

BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	222,829,916	170,691,287
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.41	$ 0.45
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	222,829,916	170,691,287

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	2006
Net income	$ 92,677	$ 76,681
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17,970)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	(2,221)	158,916
Change in value of available-for-sale securities	(98)	(401)
Minority interests	(2,700)	(67,473)
Comprehensive income	$ 69,688	$ 144,025

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ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES:		
Net income	$ 92,677	$ 76,681
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	75,406	52,840
Amortization in interest expense	2,441	1,697
Provision for loss on accounts receivable	544	563
Gain on disposal of assets	(14,310)	(2,212)
Non-cash unit-based compensation expense	8,137	4,385
Non-cash executive compensation	442	
Distribution in excess of earnings (losses) of affiliates, net	4,448	(4,742)
Deferred income taxes	37	(3,199)
Minority interests and other non-cash	88,063	50,204
Subsidiary distributions to minority unitholders	(61,517)	(75,868)
Net change in operating assets and liabilities, net of acquisitions	(49,250)	218,586
Net cash provided by operating activities	147,118	318,935
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(337,092)	(67,089)
Capital expenditures	(647,735)	(331,489)
Advances to and investment in affiliates	(32,594)	(953,247)
Proceeds from the sale of assets	21,478	7,644
Net cash used in investing activities	(995,943)	(1,344,181)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,742,802	2,911,149
Principal payments on debt	(1,062,272)	(1,941,610)
Subsidiary equity offering net of issue costs	234,887	
Net proceeds from issuance of Common Units		213,287
Distributions to Partners	(87,174)	(39,867)
Debt issuance costs	(211)	(21,302)
Net cash provided by financing activities	828,032	1,121,657
INCREASE IN CASH AND CASH EQUIVALENTS	(20,793)	96,411
CASH AND CASH EQUIVALENTS, beginning of period	77,350	26,204
CASH AND CASH EQUIVALENTS, end of period	$ 56,557	$ 122,615

NON-CASH INVESTING AND FINANCING ACTIVITIES SUPPLEMENTAL CASH FLOW INFORMATION:				
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$	3,896	$	532,631
Issuance of common units in connection with certain acquisitions	$	1,400	$	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid during the period for interest, net of interest capitalized	$	79,084	$	50,480
Cash paid during the period for income taxes	$	9,135	$	6,197

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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 and that any material information relating to us is accumulated and communicated to our management, including the President and Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosures. Our management including the President 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.

An evaluation was performed under the supervision and with the participation of our management, including the President 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) as of the end of the period covered by this report. Based upon that evaluation, management, including the President and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2008 to provide reasonable assurance that information required to be disclosed by us in the reports that we file to submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms.

Management s Report on Internal Controls over Financial Reporting

The management of Energy Transfer Equity, 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 President 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).

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2008.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2008, as stated in their report which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Equity, L.P.

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We have audited Energy Transfer Equity, L.P. s (a Delaware limited partnership) internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Energy Transfer Equity, 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 Equity, 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.

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 Equity, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

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 Equity, L.P. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for the year ended December 31, 2008, for the four months ended December 31, 2007, and for each of the two years in the period ended August 31, 2007 and our report dated February 27, 2009 expressed an unqualified opinion on those consolidated financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas

February 27, 2009

Changes in Internal Controls over Financial Reporting

There has been no change 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 December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Partnership Management

LE GP, LLC is our General Partner. Our General Partner manages and directs all of our activities. Our officers and directors are officers and directors of LE GP, LLC. The members of our General Partner elect our General Partner s Board of Directors. The board of directors of our General Partner has the authority to appoint our executive officers, subject to provisions in the limited liability company agreement of our General Partner. Pursuant to other authority, the board of directors of our General Partner may appoint additional management personnel to assist in the management of our operations and, in the event of the death, resignation or removal of our chief executive officer, to appoint a replacement. All of the current directors of our General Partner also serve as directors of the General Partner of ETP.

Corporate Governance

The Board of Directors of our General Partner has adopted both a Code of Business Conduct and Ethics applicable to our directors, officers and employees, and Corporate Governance Guidelines for directors and the Board. Current copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and charters of the Audit and Compensation Committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Unitholder requesting such information.

Annual Certification

The Parent Company has 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 2008, our President and Chief Financial 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.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts 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 Parent Company and our Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Parent Company to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Parent Company. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Parent Company, approved by all partners of the Parent Company and not a breach by the General Partner or its Board of Directors of any duties they may owe the Parent Company or the 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 Parent Company s 2008 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.

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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 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. Paul E. Glaske, Bill W. Byrne and John D. Harkey, Jr. serve as elected members of the Audit Committee. Mr. Harkey currently serves as the Chair of the Committee. Mr. Harkey currently serves as a member or chairman of the audit committee of three 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 ETP. 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 LE GP, 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 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 our General Partner, the Parent Company, ETP or its subsidiaries. Paul E. Glaske and Bill W. Byrne serve as the members of 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 and Ethics

The Board of Directors has adopted a Code of Business Conduct and Ethics 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 and Ethics 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 and Ethics 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 and Ethics 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. Our non-management directors alternate as the presiding director of such meetings.

We have 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 independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person, committee or group to the attention of Sonia Aubé at Energy Transfer Equity, L.P., 3738 Oak Lawn Avenue, Dallas, Texas, 75219. 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 February 28, 2009. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Our General Partner
John W. McReynolds	58	Director, President and Chief Financial Officer
Sonia W. Aubé	44	Vice-President of Administration and Secretary
Kelcy L. Warren	53	Director and Chairman of the Board
Ray C. Davis	67	Director
Kenneth A. Hersh	46	Director
David R. Albin	49	Director
K. Rick Turner	50	Director
Bill W. Byrne	79	Director
Paul E. Glaske	75	Director
John D. Harkey, Jr	48	Director

Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:

John W. McReynolds. Mr. McReynolds has served as our President since March 2005 and served as a Director and Chief Financial Officer since August 2005. He is also a director of Energy Transfer Partners. Prior to becoming President of Energy Transfer Equity, Mr. McReynolds was a partner with the international law firm of Hunton & Williams LLP, for over 20 years. As a lawyer, Mr. McReynolds specialized in energy-related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in numerous arbitration, litigation and governmental proceedings.

Sonia W. Aubé. Mrs. Aubé was appointed as our Vice-President of Administration and Secretary on January 23, 2009. Mrs. Aubé has served as our Secretary since October 12, 2005. Prior to joining Energy Transfer Equity, Mrs. Aubé served as the Director of Business Development of the Dallas office of Hunton & Williams LLP, a national law firm.

Kelcy L. Warren. Mr. Warren was appointed Co-Chairman of the Board of Directors of our General Partner, LE GP, LLC, effective upon the closing of our IPO. On August 15, 2007, Mr. Warren became the sole Chairman of the Board of our General Partner and the Chief Executive Officer and Chairman of the Board of the General Partner of ETP. Prior to that, Mr. Warren had served as Co-Chief Executive Officer and Co-Chairman of the Board of the General Partner of ETP since the combination of the midstream and intrastate transportation storage operations of ETC OLP and the retail propane operations of Heritage in January 2004. Mr. Warren also serves as Chief Executive Officer of the General Partner of ETC OLP. Prior to the combination of the operations of ETP and Heritage Propane, Mr. Warren served as President of the General Partner of ET Company I, Ltd. the entity that operated ETP 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 President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 25 years of business experience in the energy industry.

Ray C. Davis. Mr. Davis served as Co-Chairman of the Board of Directors of our General Partner, LE GP, LLC, effective upon the closing of our IPO until his retirement effective August 15, 2007. Mr. Davis also served as Co-Chief Executive Officer and Co-Chairman of the Board of Directors of the General Partner of ETP since the combination of the midstream and transportation operations of ETC OLP and the retail propane operations of Heritage in January 2004 until his retirement from these positions

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effective August 15, 2007. Mr. Davis also served as Co-Chief Executive Officer of the General Partner of ETC OLP, and as Co-Chief Executive Officer of ETP and Co-Chairman of the Board 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 ETP and Heritage Propane, 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.

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 Energy Transfer Partners GP since February 2004 and has served as a director of our General Partner since October 2002.

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 Energy Transfer Partners GP since February 2004 and has served as a Director of our General Partner since October 2002.

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 ETP and our General Partner. 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. Mr. Turner has served as a director of our General Partner since October 2002.

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 ETP s General Partner since 1992 and is a member of both the Audit Committee and the Compensation Committee of ETP s General Partner. Mr. Byrne is a former president and director of the National Propane Gas Association (NPGA). Mr. Byrne has served as a director of our General Partner since May 2006.

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 served as a member of the board of directors of BorgWarner, Inc. of Chicago, Illinois until April 2008. 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 ETP s General Partner since February 2004 and is chairman of ETP s Audit Committee. Mr. Glaske has served as a director of our General Partner since May 2006.

John D. Harkey, Jr. Mr. Harkey has served as Chief Executive Officer and Chairman of Consolidated Restaurant Companies, Inc., since 1998. Mr. Harkey currently serves on the Board of Directors and Audit Committee of Leap Wireless International, Inc., Loral Space & Communications, Inc., Emisphere Technologies, Inc., and the Board of Directors for the Baylor Health Care System Foundation. He also serves on the President s Development Council of Howard Payne University, Baylor Health Care Foundation and 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 of our General Partner and member of the Audit Committee.

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Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Parent Company.

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 our year ended December 31, 2008, all filing requirements applicable to its officers, directors, and greater than 10% beneficial owners were met in a timely manner other than one late Form 4 filing for Ray C. Davis.

ITEM 11. EXECUTIVE COMPENSATION

Overview

Since we are a limited partnership, we are managed by our general partner, LE GP, LLC, referred to herein as our General Partner . Our General Partner is owned by Mr. Kelcy Warren (40.6%), Mr. Ray Davis (18.8%) and Enterprise GP Holdings (40.6%). NGP, who previously held an interest in our General Partner, sold all of its interest in our General Partner in January 2009. Our limited partner interests are owned approximately 49.0% by affiliates and approximately 51.0% by the public. We own 100% of ETP GP and its general partner, ETP LLC. We refer to ETP GP and ETP LLC together as the ETP GP Entities . ETP GP is the general partner of ETP. All of ETP s employees receive employee benefits from the operating partnerships of ETP. Pursuant to a shared services agreement, we receive administrative and other services from ETP for which we pay approximately $500,000 per year.

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 officer of our General Partner performs all of our management functions. As a result, the executive officer of our General Partner is essentially our executive officer, and his compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officer of our General Partner. To provide comprehensive disclosure of executive compensation for the entire consolidated reporting group, we are also providing information as to the executive compensation of the ETP GP Entities even though none of these persons is an executive officer of the Parent Company. Accordingly, the persons we refer to in this discussion as our named executive officers are the following:

ETE Executive Officer

John W. McReynolds, President and Chief Financial Officer of our General Partner.

ETP GP Entities Executive Officers

Kelcy L. Warren, Chief Executive Officer;

Mackie McCrea, President and Chief Operating Officer;

Martin Salinas, Jr., Chief Financial Officer;

Jerry J. Langdon, Chief Administrative and Compliance Officer; and

Thomas P. Mason, Vice President, General Counsel and Secretary.

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In addition to the named executive officers of the ETP GP Entities identified above, the following individuals were executive officers of the ETP GP Entities during the year ended December 31, 2008 but were no longer executive officers as of December 31, 2008:

Brian J. Jennings, former Chief Financial Officer; and

R.C. Mills, former President - Propane.

Our Philosophy for Compensation of Executives

Our General Partner. 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.

ETP GP Entities. The ETP GP Entities also believe that a significant portion of their executives compensation should be incentive-based and have instituted an annual discretionary cash bonus that is 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 ETP s equity incentive plans which are intended to provide a longer term incentive to their key employees to focus their efforts to increase the market price of ETP s publicly traded units and to increase the cash distribution ETP pays to its Unitholders. Under its 2004 Unit Plan, ETP has 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 ETP s units (appreciation in market price for ETP s units plus the total amount of cash distributions for ETP s fiscal year) as compared to the total return of a peer group of other publicly traded limited partnerships determined by the Compensation Committee of ETP s General Partner. Commencing in 2007, ETP discontinued issuing restricted unit awards that vest based on the achievement of performance objectives and, in lieu thereof, we commenced issuing restricted unit awards that vest over a specified time period, with substantially all of these types of unit awards vesting over a five-year period at 20% per year based on continued employment through each specified vesting date. The ETP GP Entities believe that these equity-based incentive arrangements are important in attracting and retaining executive officers and key employees as well as motivating these individuals to achieve ETP s business objectives. The equity-based compensation reflects the importance of aligning the interests of the executive officers with those of ETP s Unitholders.

While ETE is responsible for the direct payment of the compensation of our named executive officer as an employee of ETE, ETE does not participate or have any input in any decisions as to the compensation levels or policies of our General Partner or the ETP GP Entities. As discussed below, ETE established a Compensation Committee in October of 2008, which is responsible for the compensation policies and compensation level of the executive officer of our General Partner.

ETP also does not participate or have any input in any decisions as to the compensation policies of the ETP GP Entities or the compensation levels of the executive officers of the ETP GP Entities. The compensation committee of the board of directors of the ETP GP Entities (the ETP Compensation Committee) is responsible for the approval of the compensation policies and the compensation levels of the executive officers of the ETP GP Entities.

ETE and ETP directly incur the payment to our respective executive officers in lieu of receiving an allocation of overhead related to executive compensation from their respective general partner. For the year ended December 31, 2008, ETE and ETP paid 100% of the compensation of the executive officers of their respective general partner as each entity represents the only business managed by such general partner.

Distributions to Our General Partner

Our General Partner 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 its general partner interest as 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 officer. Distributions to our General Partner are described in detail in Note 7 to our consolidated financial statements. Our named

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executive officer also owns directly and indirectly certain of our limited partner interests and, accordingly, receives 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 officer.

For a more detailed description of the compensation of our named executive officers, please see Compensation Tables below.

Compensation Committee of ETP and ETE

We are a limited partnership and our units are listed on the NYSE. ETP is also a limited partnership whose units are listed on the NYSE. Although the rules of the NYSE do not require publicly traded limited partnerships to have a compensation committee, the board of directors of ETP s general partner has established a Compensation Committee. The board of directors of our General Partner established our Compensation Committee in October of 2008 by appointing Bill W. Byrne and Paul E. Glaske as its initial members. Mr. Glaske serves as the chair of the Compensation Committee.

The responsibilities of the ETP Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of the Chief Executive Officer, or the CEO;
- annually evaluate the CEO s performance in light of these goals and objectives, and make recommendations to the board of directors of ETP s 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 ETP s 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 ETP s equity incentive plans;
- 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 ETP s general partner.

The responsibilities of our Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of our President and Chief Financial Officer, or CFO;

annually evaluate the President and CFO 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 President and CFO s compensation levels based on this evaluation;

make determinations with respect to the grant of equity-based awards to executive officers under ETE s equity incentive plans;

periodically evaluate the terms and administration of ETE s long-term incentive plans to assure that they are structured and administered in a manner consistent with ETE 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, President and CFO or executive officer compensation; and

perform other duties as deemed appropriate by the board of directors of our General Partner.

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Compensation Objectives

Each of our compensation programs 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

Presently, the Compensation Committees of ETP and ETE consider relevant data available to them to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officer. Our board of directors and the Compensation Committee also consider individual performance, levels of responsibility, skills and experience.

Components of Executive Compensation

For the year ended December 31, 2008, the compensation paid to our named executive officer consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses; and
- equity incentive plan compensation.

The compensation paid to the named executive officers of the ETP GP Entities, other than ETP s CEO, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of cash bonuses;
- vesting of previously issued equity-based awards issued pursuant to ETP s 2004 Unit Plan;
- compensation resulting from the vesting of equity issuances made by an affiliate; and

401(k) plan contributions.

Mr. Warren, ETP s CEO, has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits) after 2007.

In October 2007, the Compensation Committee of the ETP GP Entities engaged Mercer Consulting Services to assist in the determination of compensation levels for ETP s executive officers for the year ended December 31, 2008. The consultant provided an analysis of compensation for senior executives at a group of 14 companies in the energy industry, comprised primarily of midstream and exploration and production companies, with respect to annual salary, annual cash bonus and long-term incentive arrangements. The Compensation Committee utilized the information provided by Mercer Consulting Services as general comparisons of levels of base salary, annual bonus and long-term equity incentives at theses other companies with those of the named executive officers of the ETP GP Entities in order to assure competitiveness of the compensation of its named executive officers with the compensation for executive officers of these other companies. The Compensation Committee did not attempt to benchmark the base salary, annual bonus or long-term equity incentives to any percentage of, ETP s numerical average of, the compensation levels at these other companies. In addition to this information, the Compensation Committee of the ETP GP Entities also considered the financial performance of ETP for its 2007 fiscal year and its four-month transition period ended December 31, 2007 as well as the individual contributions of its named executive officers in achieving this financial performance and in developing and executing projects for ETP s future growth.

Base Salary. For the year ended December 31, 2008, the base salary level, equity incentive compensation and the non-equity incentive compensation of Mr. McReynolds, the President and Chief Financial Officer of ETE s General Partner, was determined by the board of directors of our General Partner in 2008 based on recommendations from our Compensation Committee which took into account the compensation for senior executives at comparable companies with respect to annual salary, annual cash bonus and long-term incentive arrangements, and the total compensation for similarly situated senior executives at ETP.

The base salaries of the named executive officers of the ETP GP Entities for the year ended December 31, 2008 were determined by the board of directors of the ETP GP Entities in 2007 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 the ETP GP Entities. In May 2008, the Board of Directors of ETP s General Partner promoted Mr. McCrea from President Midstream to President of the Partnership. In August 2008, the Compensation Committee approved an increase in the annual base salary of Mr. McCrea to $500,000 in light of his greater responsibilities in this new position. In June 2008, the Board of Directors of ETP s General Partner promoted Mr. Salinas from Controller to Chief Financial Officer following the resignation of Brian J. Jennings as Chief Financial Officer. In August 2008, the Compensation Committee approved an increase in the annual base salary of Mr. Salinas to $350,000 in light of his greater responsibilities in this new position. In August 2008, the Compensation Committee also approved increases in the annual base salaries of Mr. Langdon and Mr. Mason to $335,000 and $420,000, respectively, which amounts reflect increases of 3.0% and 5.0%, respectively, from their prior annual base salaries. The Compensation Committee determined that such increases in annual base salary for Mr. Langdon and Mr. Mason were warranted in light of their individual performance and levels of responsibility related to the management of the ETP GP Entities.

Annual Bonus. The bonus payment awarded to Mr. McReynolds in December 2008 was a fixed amount determined by our Compensation Committee.

In addition to base salary, the named executive officers of the ETP GP Entities, other than ETP s CEO, receive discretionary annual cash bonuses that are paid in a lump sum following the end of the fiscal year (or, in the case of our four-month transition period ended December 31, 2007, following such transition period) to reward the named executive officers of the ETP GP Entities for the achievement of financial performance objectives during the year for which the bonuses are awarded in light of the contribution of each individual to ETP s profitability and success during the period for which the bonuses are awarded. In this regard, the Compensation Committee takes into account whether ETP achieved or exceeded its publicly announced EBITDA guidance for the period as an important element in making its determinations with respect to annual bonuses; however, the Compensation Committee does not establish its own financial performance objectives in advance for purposes of making those determinations. The Compensation Committee also considers the recommendation of ETP s CEO in determining the specific cash bonus amounts for each of the other named executive officers. The Compensation Committee considers the recommendation of ETP s CEO in determining specific cash bonus amounts for each of the other named executive officers of the ETP GP Entities.

For our fiscal year ended August 31, 2007, the Compensation Committee approved a cash bonus for each of the named executive officers of the ETP GP Entities, other than ETP s CEO, based in part upon ETP s success in exceeding its internal financial budget for such year. Similarly, for the four-month period ended December 31, 2007 (the transition period related to the change in our fiscal year end from August 31 to December 31), the Compensation Committee approved a cash bonus for each of the named executive officers of the ETP GP Entities, other than ETPs s CEO, based in part upon ETP s success in exceeding its internal financial budget for such four-month period. In each case, the financial budgets for such periods were presented to the Board of Directors of ETP s General Partner for review and approval prior to the beginning of each such period. These internal financial budgets are generally developed for each business segment, and then aggregated with appropriate corporate level adjustments to (i) reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all segments of the Partnership s business. The evaluation of the Partnership s performance versus its internal financial budget is based on earnings without giving consideration to the impact of interest, income taxes, or certain other non-cash items, such as depreciation and amortization. In general, the Compensation Committee believes that Partnership performance at or above the internal financial budget would support bonuses to named executive officers of the ETP GP Entities ranging from 100% to 150% of their annual salary. The individual bonus amounts for each named executive officer of the ETP GP Entities, other than ETP s CEO, also reflect the Compensation Committee s view of the impact of such individual s efforts and contributions towards achievement of ETP s success in exceeding it internal financial budget in developing new projects as well as towards the overall management of ETP s business.

ETP Equity Awards. Each of ETP s 2004 Unit Plan and 2008 Incentive Plan authorizes the Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other rights related to ETP units at such times and upon such terms and conditions as it may determine in accordance with each such plan. The Compensation Committee determined and/or approved the terms of the unit grants awarded to the named executive officers of the ETP GP Entities, including the number of Common Units subject to the unit award and the vesting structure of those unit awards. All of the awards granted to the named executive officers under these equity incentive plans have consisted of restricted unit awards which have required the achievement of performance objectives in order for the awards to become vested or restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any unit award, ETP Common Units are issued. Each of Messrs. Warren, McCrea, Salinas, Langdon, Mason, and Davis previously received unit awards under the 2004 Unit Plan, a portion of which vested during our 2008 fiscal year.

Generally, each award subject to the achievement of performance objectives 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, with 100% of such one-third vesting if the total return for ETP s 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 ETP s 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 ETP s 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 ETP s units for the year plus the aggregate per unit cash distributions received for the year. For the twelve-month period ended August 31, 2008, the peer group used to make the ETP 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., Magellan Midstream Partners, L.P., AmeriGas Partners, L.P., ONEOK Partners, L.P., Buckeye Partners, L.P., Kinder Morgan Energy Partners, L.P., Enterprise Products Partners L.P., TEPPCO Partners, L.P., Enbridge Energy Partners, L.P. and Ferrellgas Partners, L.P. The vesting of these awards is also subject to continued employment with ETP or its General Partner as of the end of each applicable year.

In October 2008, the Compensation Committee determined that, of the unit awards subject to the achievement of performance objectives, 25% of the ETP Common Units subject to such awards eligible to vest on September 1, 2007 became vested and 75% of the awards were forfeited based on ETP s performance for the twelve-month period ended August 31, 2008. In October 2008, the Compensation Committee approved a special grant of new unit awards that entitled each holder to receive a number of ETP Common Units equal to the number of ETP Common Units forfeited as of September 1, 2007, which new unit awards became fully vested on October 15, 2008. These Compensation Committee actions affected all ETP employee unit awards, including unit awards granted to ETP s named executive officers.

ETP has also granted restricted unit awards to its employees that vest over a specified time period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. In October 2008 and December 2008, the Compensation Committee approved the grant of new unit awards under ETP s 2004 Unit Plan and its 2008 Incentive Plan to approximately 275 of its employees, including certain of ETP s named executive officers. All of these unit awards provided for vesting over a five-year period at 20% per year, subject to continued employment through each specified vesting date. These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. Of the named executive officers of the ETP GP Entities, Messrs. McCrea, Salinas, Langdon and Mason received grants relating to 20,000, 20,000, 12,000 and 70,000 ETP Common Units, respectively. In approving the grant of such unit awards, the Compensation Committee took into account the same factors as discussed above under the caption -Annual Bonus , the long-term objective of retaining such individuals as key drivers of the ETP s future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity unit awards subject to vesting.

The issuance of ETP Common Units pursuant to ETP s equity inventive plans 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 ETP Common Units.

The unit awards under ETP s equity incentive plans 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 December 31, 2008, the Compensation Committee did not accelerate the vesting of any unvested unit awards granted under ETP s equity incentive plans, except for 10,583 unvested units held by Mr. Mills that were accelerated upon his retirement in May 2008.

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Affiliate Equity Awards. During 2007, Mr. Jennings and Mr. Mason received awards from a partnership, the general partner of which is owned and controlled by Mr. McReynolds. These awards were granted as an inducement for these persons to accept employment with ETP and as an incentive to these persons to contribute to ETP s success. The rights granted include the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the recipient will vest in the ETE units at a rate of 20% per year. These awards were made in the sole discretion of Mr. McReynolds. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by us or ETP unless this partnership defaults under its obligations pursuant to these unit awards, in which case ETP is obligated to deliver ETE units to the recipients at the same times and in the same quantities as specified in the unit awards from this partnership. 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 December 31, 2008 result in a total non-cash compensation expense of approximately $10.3 million to be recognized over the related vesting 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.

Rights related to 60,000 ETE units vested in March 2008, rights related to 20,000 ETE units vested in June 2008, and rights related to 55,000 ETE units vested in December 2008. In June 2008, rights related to 240,000 ETE units were forfeited due to the resignation of an officer of ETP.

In July 2008, rights related to 240,000 ETE units were awarded to Mr. Salinas and in December 2008, rights related to 210,000 ETE units were awarded to Mr. McCrea, both in connection with their respective promotions to their current positions. These awards have similar terms to those discussed above, including vesting over five years at 20% per year. As discussed above, none of the costs related to these awards will be paid by either ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these unit awards are viewed as compensation to these recipients for financial reporting purposes and as ETP has an obligation to deliver ETE units in the event this partnership does not fulfill its obligations pursuant to these unit awards, the Compensation Committee also considered and approved these unit awards.

Qualified Retirement Plan Benefits. Each of ETE and ETP 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 December 31, 2008, the Compensation Committee approved an employer matching contribution of up to six percent.

Health and Welfare Benefits. All full-time employees, including our and ETP s executive officers, may participate in our health and welfare benefit programs including medical coverage and disability insurance.

Termination Benefits. Our and ETP s 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. Each of ETP s 2004 Unit Plan and 2008 Incentive 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 each of ETP s plans mean 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 the year ended December 31, 2008. The value of unvested ETP unit awards that would fully vest upon a change of control as defined in ETP s equity incentive plans was $170,050 for Mr. Warren, $1,403,525 for Mr. McCrea, $888,817 for Mr. Salinas, $734,616 for Mr. Langdon, and $2,870,444 for Mr. Mason based on the closing unit price per ETP Common Unit on December 31, 2008. The value of unvested affiliate equity awards that would fully vest upon a change of control as defined in the affiliate equity awards was $3,404,100 for Mr. McCrea, $3,890,400 for Mr. Salinas, $1,296,800 for Mr. Langdon, and $2,674,650 for Mr. Mason, based on the closing unit price per ETE Common Unit on December 31, 2008.

Deferred Compensation Arrangements. We and ETP do not have any deferred compensation arrangements or defined benefit pension plans or other post retirement benefits for our named executive officers. Our and ETP s named executive officers also do not receive any payments that would represent a perquisite.

ETP Director Compensation

The ETP Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of ETP s General Partner. On October 17, 2006, the ETP Compensation Committee recommended, following its receipt and review of an independent third-party compensation study, and the ETP 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 ETP s General Partner will be equal to $25,000 divided by the fair market value of Common Units September 1 of each year. As all units available to be issued under the 2004 Unit Plan have been issued or are otherwise reserved for issuance due to the grant of unit awards under this plan, no further grants of ETP Common Units to non-employee directors will be made under this plan.

In October 2008, the Board of Directors of ETP s General Partner approved the adoption of the 2008 Incentive Plan, subject to approval of ETP s Unitholders. In December 2008, ETP s Unitholders approved the 2008 Incentive Plan. The 2008 Incentive Plan provides for annual grants of ETP Common Units to non-employee directors of ETP s General Partner equal to $50,000 divided by the fair market value of ETP s Common Units as of each anniversary of December 16, 2008, the date of the adoption of the 2008 Incentive Plan.

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 officer is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

We and ETP account for our unit-based compensation arrangements, including equity-based awards issued to certain of ETP s named executive officers by Mr. McReynolds (as discussed above), in accordance with the requirements of SFAS No. 123R over the vesting period of the awards, as discussed further in Note 8 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm, Byrne and Davis served on the Compensation Committee of the ETP GP Entities during 2008. During 2008, none of the members of the committee was an officer or employee of ETP or any of its subsidiaries or served as an officer of any company with respect to which any of its executive officers served on such company s board of directors. In addition, neither Mr. Grimm nor Mr. Byrne are former employees of the ETP GP Entities or any of its subsidiaries. Mr. Davis is associated with business entities with which ETP have relationships. See Item 13, Certain Relationships and Related Transactions, and Director Independence.

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 Equity, 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 Form10-K.

The Compensation Committee of the Board of Directors of LE GP, LLC, the general partner of Energy Transfer Equity, L.P.

Paul E. Glaske
Bill W. Byrne

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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.

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Compensation Tables

Summary Compensation Table

Name and Principal Position	Year (1)	Salary ($)	Bonus ($) (2)	Equity Awards ($) (3)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (4)	Total ($)
ETE Officer:									
John W. McReynolds	2008	$ 406,923	$ 600,000	$	$	$	$	$ 9,346	$ 1,016,269
President and Chief Financial Officer	Transition	138,641	38,410						177,051
	2007	399,228	600,000					9,346	1,008,574
ETP Officers:									
Kelcy L. Warren (5)	2008	$ 2,272	$	$ (99,407)	$	$	$	$	$ (97,135)
Chief Executive Officer	Transition	220,429		37,120				4,846	262,395
	2007	500,000		209,998				14,000	723,998
Mackie McCrea	2008	444,154		873,061				152,216	1,469,431
President and Chief Operating	Transition	177,926	200,000	106,355				5,327	489,608
Officer	2007	380,769	600,000	150,303				14,481	1,145,553
Martin Salinas, Jr. (6)	2008	261,539		239,000				1,557,912	2,058,451
Chief Financial Officer									
Jerry J. Langdon (7)	2008	356,058		240,659				1,696,983	2,293,700
Chief Administrative and	Transition	121,154	125,000					649,228	895,382
Compliance Officer	2007	53,846	62,500					324,614	440,960
Thomas P. Mason (8)	2008	437,277		549,477				2,512,719	3,499,473
Vice President, General	Transition	130,769	167,000					1,316,134	1,613,903
Counsel and Secretary	2007	238,462	291,667					2,478,593	3,008,722
Brian J. Jennings (9)	2008	744,447		(912,982)				623,815	455,280
Former Chief Financial Officer	Transition	265,105	200,000					701,815	1,166,920
	2007	189,231	300,000					2,387,910	2,877,141

(1) Amounts presented for 2008 are based on the calendar year of January 1, 2008 to December 31, 2008. Amounts presented as Transition include the four months of September 1, 2007 through December 31, 2007. Amounts for 2007 are based on a fiscal year of September 1, 2006 to August 31, 2007.

(2) The cash bonus amounts to be paid to ETP named executive officers for calendar year 2008 have not yet been determined. We recorded accruals for the total bonus estimated for ETP s named executive officers for calendar year 2008. The annual bonuses for ETP s named executive officers for 2008 are subject to determination by the Compensation Committee and are expected to be paid in March 2009. The bonus amounts presented above for Transition for the named executive officers of ETP represent the discretionary cash bonus paid in 2008 relating to the four-month period ended December 31, 2007, which bonus payment was made in connection with the transition from a fiscal year ending on August 31 to a fiscal year ending December 31. The bonus amounts presented for 2007 for the named executive officers of ETP represent the discretionary cash bonus paid in December 2007 for the fiscal year ended August 31, 2007.

(3) The amounts in this column reflect the amount of compensation expense recognized in our consolidated financial statements determined in accordance with SFAS 123(R). Compensation expense is recognized based on the grant-date fair value of the award, which is measured as the market price of the number of Common Units expected to be issued upon vesting. For awards that do not receive distribution

equivalents prior to vesting, the market price is reduced by the present value of the expected distributions on our Common Units during the vesting period. The compensation expense for calendar year 2008 and fiscal year 2007 is net of the impact of the cumulative adjustment of prior period compensation expense resulting from the unit forfeitures in 2008 and 2007 due to the failure to achieve specified performance conditions. The negative compensation expense reflected for Mr. Warren in 2008 relates to performance awards that did not vest. The negative compensation expense reflected above for Mr. Jennings is due to the reversal of previously recorded compensation expense resulting from the forfeiture of units upon his resignation.

(4) The amounts in this column include (a) the amount of compensation expense recognized in our consolidated financial statements 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 7 to our consolidated financial statements, and (b) contributions to the 401(k) plan made by ETP on behalf of the named executive officers.

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(5) Mr. Warren voluntarily determined that after 2007, (a) his salary 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 and (c) he will no longer accept any equity awards under the equity incentive plans beginning in 2008.

(6) Mr. Salinas was promoted to Chief Financial Officer effective June 16, 2008. The 2008 amounts reflect his compensation for the entire year.

(7) Mr. Langdon began employment on July 1, 2007. Thus, the 2007 amounts only reflect compensation from his date of employment through August 31, 2007.

(8) Mr. Mason began employment on February 1, 2007. Thus, the 2007 amounts only reflect compensation from his date of employment through August 31, 2007. Effective June 2008, Mr. Mason became the Vice President, General Counsel and Secretary.

(9) Mr. Jennings began employment on March 6, 2007 and resigned on June 16, 2008.

All Other Compensation Table

Name	Year (1)	Perquisites and Other Personal Benefits ($)	Tax Reimbursements ($)	Life Insurance Premiums ($) (2)	Company Contributions to Retirement and 401(k) Plans ($) (3)	Severance Payments / Accruals ($)	Change in Control Payments / Accruals ($) (4)	Affiliate Equity Awards (5)	Total ($)
ETE Officer:									
John W. McReynolds	2008	$	$	$	$ 9,346	$	$		$ 9,346
President and Chief Financial	Transition								
Officer	2007				9,346				9,346
ETP Officers:									
Kelcy L. Warren	2008	$	$	$	$	$	$	$	$
Chief Executive Officer	Transition				4,846				4,846
	2007				14,000				14,000
Mackie McCrea	2008				14,908			137,308	152,216
President and Chief Operating	Transition				5,327				5,327
Officer	2007				14,481				14,481
Martin Salinas, Jr.(6)	2008				12,769			1,314,743	1,327,512
Chief Financial Officer									
Jerry J. Langdon	2008							1,521,183	1,521,183
Chief Administrative and	Transition							649,228	649,228
Compliance Officer	2007							324,614	324,614
Thomas P. Mason	2008				5,480			2,435,684	2,441,164
Vice President, General Counsel	Transition				6,462			1,309,672	1,316,134
and Secretary	2007							2,478,593	2,478,593
Brian J. Jennings (7)	2008				4,615			348,600	353,215
Former Chief Financial Officer	Transition				4,615			697,200	701,815
	2007							2,387,910	2,387,910

(1) Amounts presented for 2008 are based on the calendar year of January 1, 2008 to December 31, 2008. Amounts presented as Transition include the four months of September 1, 2007 through December 31, 2007. Amounts presented for 2007 are based on a fiscal year of September 1, 2006 to August 31, 2007.

(2) 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.

(3) Vesting in the 401(k) matching contribution occurs upon the completion of one year of service. Matching contributions for officers with less than one year of service are reflected in the period during which they vest.

(4) 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 our equity incentive plans, which value was $170,050 for Mr. Warren, $1,403,525 for Mr. McCrea, $888,817 for Mr. Salinas, $734,616 for

Mr. Langdon, and $2,870,444 for Mr. Mason based on the closing unit price per ETP Common Unit on December 31, 2008.

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Also does not include the December 31, 2008 value of unvested affiliate equity awards granted to Messrs. McCrea, Salinas, Langdon and Mason, that would fully vest upon a change of control as defined in the affiliate equity awards, which value was $3,404,100 for Mr. McCrea, $3,890,400 for Mr. Salinas, $1,296,800 for Mr. Langdon, and $2,674,650 for Mr. Mason, based on the December 31, 2008 closing unit price per ETE Common Unit. Messrs. McCrea and Salinas did not have affiliate equity awards in the 2007 period. Mr. Jennings forfeited the remaining unvested balance of affiliate equity awards upon his resignation in June 2008.

(5) Consists of the amount of compensation expense recognized in our consolidated financial statements related to equity-based awards of units in ETE owned by an affiliate to certain of ETP s named executive officers for the calendar year ended December 31, 2008, the four-month transition period ended December 31, 2007 and the fiscal year ended August 31, 2007. During the year ended December 31, 2008, $106,667, $426,500 and $348,600 of the affiliate equity awards vested for Mr. Mason, Mr. Langdon and Mr. Jennings, respectively. No other portion of the affiliate equity awards had vested as of December 31, 2008, December 31, 2007 or August 31, 2007.

(6) Mr. Salinas was promoted to Chief Financial Officer effective June 16, 2008. The 2008 amounts reflect his compensation for the entire year.

(7) Mr. Jennings resigned on June 16, 2008.

Grants of Plan-Based Awards Table

		Estimated Future Payouts Under Equity Incentive Plan Awards						
Name	**Grant Date**	**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 (2)**
ETE Officer:								
Jonn W. McReynolds President and Chief Financial Officer	12/19/08				50,000		$	$ 832,000
ETP Officers:								
Kelcy L. Warren Chief Executive Officer	11/01/06		15,000	15,000			$	$ 406,490
Mackie McCrea President and Chief Operating	12/22/08				20,000			681,800
Officer	10/07/08				4,750			143,878
	12/05/07				22,000			912,982
	10/02/07				8,749			400,879
	11/01/06		11,000	11,000				298,106
Martin Salinas, Jr. (3)	12/22/08				20,000			681,800
Chief Financial Officer	10/07/08				1,501			45,465
Jerry J. Langdon	12/22/08				12,000			409,080
Chief Administrative and Compliance Officer	12/05/07				12,000			497,990
Thomas P. Mason	12/22/08				20,000			681,800
Vice President, General Counsel	10/17/08				50,000			1,651,000
and Secretary	12/05/07				18,000			746,985
Brian J. Jennings Former Chief Financial Officer								

(1) Mr. Jennings forfeited 22,000 awards upon his resignation on June 16, 2008, all of which were granted in December 2007.

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(2) We have computed the grant-date fair value of unit awards in accordance with SFAS 123(R), as further described above and in Note 8 to our consolidated financial statements.
(3) Mr. Salinas was promoted to Chief Financial Officer effective June 16, 2008. Mr. Salinas did not receive any grants of plan-based awards during the year ended December 31, 2008, other than those listed above, all of which occurred subsequent to his promotion. Mr. Salinas grants of plan-based awards prior to 2008 are not reflected.

We do not have any non-equity incentive plans.

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 issued pursuant to the ETP 2004 Unit Plan or the ETP 2008 Incentive Plan, and such awards are in the sole discretion of Mr. McReynolds. The amount of compensation expense recognized during fiscal 2008 and to be recognized in future periods for such awards is detailed above by individual recipient.

Outstanding Equity Awards at Year-End Table

		Stock Awards			
Name	**Award Year (1)**	**Number of Units That Have Not Vested (#) (2)**	**Market Value of Units That Have Not Vested ($) (2)**	**Equity Incentive Plan Awards: Number of Units That Have Not Vested (#) (3)**	**Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested ($) (4)**
ETE Officer:					
John W. McReynolds President and Chief Financial Officer	2008		$	50,000	$ 810,500
ETP Officers:					
Kelcy L. Warren Chief Executive Officer	2006		$	5,000	$ 170,050
Mackie McCrea President and Chief Operating Officer	2008 2007 2006			20,000 17,600 3,668	680,200 598,576 124,749
Martin Salinas, Jr. Chief Financial Officer	2008 2007 2006			20,000 4,800 1,334	680,200 163,248 45,369
Jerry J. Langdon Chief Administrative and Compliance Officer	2008 2007			12,000 9,600	408,120 326,496
Thomas P. Mason Vice President, General Counsel and Secretary	2008 2007			70,000 14,400	2,380,700 489,744
Brian J. Jennings Former Chief Financial Officer					

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(1) Amounts presented for 2008 are based on the calendar year of January 1, 2008 to December 31, 2008. Amounts presented as Transition include the four months of September 1, 2007 to December 31, 2007. Amounts presented for 2007 are based on a fiscal year of September 1, 2006 to August 31, 2007.

(2) 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 issued pursuant to the ETP 2004 Unit Plan or the ETP 2008 Incentive Plan, and such awards are in the sole discretion of Mr. McReynolds.

(3) For each named executive in the table, the unvested 2006 awards are scheduled to vest on September 1, 2008. The unvested 2007 awards are scheduled to vest 1/4 on September 1, 2009; 1/4 on September 1, 2010; 1/4 on September 1, 2011; and 1/4 on September 1, 2012. Included in Mr. Mason s unvested 2008 awards are 50,000 units with an aggregate market value of $1,651,000 which vest ratably on October 13 of each year through 2013. The remaining unvested 2008 awards are scheduled to vest 1/5 on December 22, 2009; 1/5 on December 22, 2010; 1/5 on December 22, 2011; 1/5 on December 22, 2012; and 1/5 on December 22, 2013.

(4) This market value for 2008 was computed as the number of unvested awards at December 31, 2008 multiplied by our Common Unit closing per unit market price at December 31, 2008. The market value for 2007 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.

Option Exercises and Units Vested Table

		Unit Awards	
Name	**Year (1)**	**Number of Units Acquired on Vesting (#)**	**Value Realized on Vesting ($) (2) (3)**
ETE Officer:			
Jonn W. McReynolds President and Chief Financial Officer	2008		$
ETP Officers:			
Kelcy L. Warren Chief Executive Officer	2008	2,000	$ 73,660
	Transition	3,500	131,673
	2007	9,000	523,702
Mackie McCrea President and Chief Operating Officer	2008	19,483	668,064
	Transition	2,917	109,740
	2007	7,999	465,457
Martin Salinas, Jr. (4) Chief Financial Officer	2008	5,450	186,310
Jerry J. Langdon Chief Administrative and Compliance Officer	2008	2,400	73,704
	Transition		
	2007		
Thomas P. Mason Vice President, General Counsel and Secretary	2008	3,600	110,556
	Transition		
	2007		
Brian J. Jennings Former Chief Financial Officer	2008		
	Transition		
	2007		

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(1) Amounts presented for 2008 are based on the calendar year of January 1, 2008 to December 31, 2008. Amounts presented as Transition include the four months of September 1, 2007 to December 31, 2007. Amounts presented for 2007 are based on a fiscal year of September 1, 2006 to August 31, 2007.

(2) This value represents the amount reported on the officer s W-2. Prior to 2008, such amounts were discounted due to time restrictions place on the sale of the units. For 2007, the value represents approximately 92% of the market value of the units on the date of vesting. Amounts vested in 2008 do not reflect such discount.

(3) 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 issued pursuant to the ETP 2004 Unit Plan or the ETP 2008 Incentive Plan, and such awards are in the sole discretion of Mr. McReynolds. With respect to these awards, Mr. Mason vested in 55,000 ETE units in December 2008 and 55,000 ETE units in December 2007; Mr. Langdon vested in 20,000 ETE units in July 2008; and Mr. Jennings vested in 60,000 ETE units in March 2008.

(4) Mr. Salinas was promoted to Chief Financial Officer effective June 16, 2008. The 2008 amount reflects units vested for the entire year.

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 the only business managed by our General Partner.
Mr. Davis is presently a non-employee director (resignation effective August 15, 2007). In fiscal year 2008, Mr. Davis received $62,243 in total compensation, including $45,920 of director fees paid in cash and $16,323 of unit awards, 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 and McReynolds (except for periods prior to his employment with ETE).

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Non-Employee, Independent Director Compensation Table

Name	Year (1)	Fees Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)	Total ($)
Directors of ETE and ETP					
K. Rick Turner					
As ETE Director	2008	$ 67,200	$ 11,675	$	$ 78,875
	2007	43,650	6,876		50,526
As ETP Director	2008	43,793	22,510		66,303
	2007	51,050	28,532		79,582
Bill W. Byrne					
As ETE Director	2008	100,200	11,467		111,667
	2007	125,725	6,876		132,601
As ETP Director	2008	71,800	22,510		94,310
	2007	68,000	19,003		87,003
Paul E. Glaske					
As ETE Director	2008	100,200	11,467		111,667
	2007	125,725	6,876		132,601
As ETP Director	2008	69,400	22,510		91,910
	2007	66,150	22,207		88,357
John D. Harkey, Jr.					
As ETE Director	2008	105,200	11,467		116,667
	2007	127,600	6,876		134,476
As ETP Director	2008	64,400	26,805		91,205
	2007	55,300	33,352		88,652
David R. Albin					
As ETE Director	2008				
	2007				
As ETP Director	2008				
	2007				
Kenneth A. Hersh					
As ETE Director	2008				
	2007				
As ETP Director	2008				
	2007				
Directors of ETP					
Ted Collins, Jr.	2008	$ 40,000	$ 22,510	$	$ 62,510
	2007	40,000	25,874		65,874
Michael Grimm	2008	49,415	26,805		76,220
	2007	44,800	33,352		78,152
John W. McReynolds (2)	2007		8,177		8,177

(1) Amounts presented for 2008 are based on the calendar year of January 1, 2008 to December 31, 2008. Amounts presented for 2007 are based on a fiscal year of September 1, 2006 to August 31, 2007.

(2) This relates to unit grants to Mr. McReynolds prior to his employment with ETE.

LE GP Director Compensation. On December 19, 2006, the board of directors of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., adopted policies regarding the compensation of its outside directors. Directors who are an employee of LE GP, ETP GP or any of their subsidiaries are not eligible for director compensation.

The compensation arrangements for outside directors include a $30,000 annual retainer for services on the board and an annual retainer ($7,500 or $10,000 in the case of the chairman) and meeting attendance fees ($1,200) for services on the Audit and Conflicts Committee. The total amount of director fees we paid during 2008 to the LE GP directors was $372,800. The total amount of director fees we paid during fiscal year 2007 to the LE GP directors was $422,700, which includes fees paid to the members of the special conflicts committee (Messrs. Byrne, Glaske and Harkey, $88,000 for fiscal 2007, each).

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The outside directors of LE GP are also entitled to an annual award under the Energy Transfer Equity, L.P. Long-Term Incentive Plan equal to $15,000 divided by (a) the closing price of the Common Units of ETE on the New York Stock Exchange on such grant-date or (b) the Fair Market Value of a common unit as otherwise determined by the Board of Directors. Each Award shall be subject to a Restricted Period of three (3) years and shall vest and be payable 1/3 per year beginning on the first anniversary date of the Award, provided that all unvested Awards shall fully vest upon the occurrence of a Change of Control. Unit awards of 406 ETE Common Units each were made in September 2007 to Messrs. Turner, Byrne, Glaske and Harkey, totaling 1,624 ETE Common Units. Unit awards of 823 ETE Common Units each were made in January 2009 to Messrs. Turner, Byrne, Glaske and Harkey, totaling 3,292 ETE Common Units. The compensation expense recorded is based on the grant-date market value of the ETE Common Units and is recognized over the vesting period. Distributions are paid during the vesting period.

The non-employee directors of ETP GP participate in ETP s 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 the ETP 2004 Unit 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 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 over three years 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 ETP unit awards vest. As all units available to be issued under the ETP 2004 Unit Plan have been issued or are otherwise reserved for issuance due to the grant of unit awards under this plan, no further grants of ETP Common Units to ETP non-employee directors will be made under this plan.

In October 2008, the Board of Directors of ETP s General Partner approved the adoption of the 2008 Incentive Plan, subject to approval of ETP s Unitholders. In December 2008, ETP s Unitholders approved the 2008 Incentive Plan. The 2008 Incentive Plan provides for annual grants of ETP Common Units to non-employee directors of ETP s General Partner equal to $50,000 divided by the fair market value of ETP s Common Units as of each anniversary of December 16, 2008, the date of the adoption of the 2008 Incentive Plan.

Compensation expense is measured on the grant-date market value of the ETP units, reduced by the present value of the distributions that will not be received during the vesting period. ETP assumed a weighted average risk-free interest rate of 3.34% and 3.80% for the years ended December 31, 2008 and 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 under the ETP 2004 Unit Plan. For the Director Awards granted during the years ended December 31, 2008 and 2007, the grant-date average per unit cash distributions were estimated to be $7.11 and $4.95, respectively.

Annual Director Grants of 3,990 units and 2,880 units were awarded, and 2,752 and 5,220 ETP Director Grants vested and ETP Common Units were issued on September 1, 2008 and 2007, respectively.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

At the time of our IPO, we adopted the Energy Transfer Equity, L.P. Long-Term Incentive Plan for the employees, directors and consultants of our general partner and its affiliates who perform services for us. The long-term incentive plan provides for the following five types of awards: restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The long-term incentive plan limits the number of units that may be delivered pursuant to awards to three million units, excluding the Class B Units. Units withheld to satisfy exercise prices or tax withholding obligations are available for delivery pursuant to other awards. The plan is administered by the compensation committee of the board of directors of our General Partner.

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The following table sets forth in tabular format, a summary of our equity plan information as of December 31, 2008:

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			
Equity compensation plans not approved by security holders			2,931,428
Total		$	2,931,428

Energy Transfer Equity, L.P. Units

The following table sets forth certain information as of February 19, 2009, 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 executive officers of the General Partner of our General Partner as a group, of our Common Units. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Title of Class	Name and Address of Beneficial Owner (1)	Beneficially Owned (2)	Percent of Class
Common Units	David R. Albin (3)	501,226	*
	Sonia Aube (4)	15,000	*
	Bill W. Byrne (5)	25,516	*
	Ray C. Davis (6)	18,902,383	8.48%
	Dan L. Duncan (7)	39,170,190	17.58%
	Paul E. Glaske	23,216	*
	John D. Harkey Jr. (8)	16,716	*
	Kenneth A. Hersh (9)	651,227	*
	John McReynolds (10)	6,931,923	3.11%
	K. Rick Turner	143,460	*
	Kelcy L. Warren (11)	42,613,159	19.08%
	All Directors and Executive Officers as a group (10 persons)	69,723,826	31.29%

* Less than one percent (1%)

(1) The address for Mr. McReynolds and Mrs. Aubé is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Mr. Warren is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Mr. Davis is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Messrs. Albin and Hersh is 125 E. John Carpenter Freeway, Suite 600, Irving, Texas 75062. The address for Messrs. Byrne, Glaske, Harkey and Turner is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Mr. Duncan is 1100 Louisiana Street, Suite 1000, Houston, Texas 77002.

(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 or to dispose or direct the disposition thereof or has the right to acquire either of those powers within sixty (60) days.

(3) Includes 487,717 Common Units held by Spectra Holdings, L.P., a limited partnership owned by Mr. Albin.

(4) Mrs. Aubé was appointed as an executive officer in January 2009.

(5) Includes 23,800 Common Units held by Byrne & Associates, LLC, an entity in which Mr. Byrne is a member and sole manager. Mr. Byrne disclaims beneficial ownership of the Common Units owned by Byrne & Associates other than to the extent of his pecuniary interest therein.

(6) Includes 742,254 Common Units held by Avatar Investments, LP and 50 Common Units held by Avatar Holdings, LLC, a limited partnership and limited liability company, respectively, owned by Mr. Davis. Mr. Davis disclaims beneficial ownership of the Common Units owned by Avatar Investments and Avatar Holdings other than to the extent of his pecuniary interests therein.

(7) Includes 180,100 Common Units owned by DD Securities LLC (Duncan LLC) and 38,976,090 Common Units owned directly by Enterprise GP Holdings L.P. (EPE). EPE Holdings, LLC (EPE Holdings) is the general partner of EPE. Duncan LLC owns 100% of the membership interests of EPE Holdings. Dan L. Duncan is the sole member of Duncan LLC. EPE Holdings, Duncan LLC, and Dan L. Duncan each have an indirect pecuniary interest in the Common Units. As of May 7, 2007, Duncan LLC owned directly Units of EPE, representing approximately 4.2% of the outstanding Units of EPE. Such persons, other than EPE, disclaim beneficial ownership of the Common Units other than the extent of their pecuniary interests therein.

(8) Includes 15,000 Common Units held by the Katemcy Trust.

(9) Includes 230,209 Common Units held by Hersh Investment Partners, L.P., a limited partnership owned by Mr. Hersh. Mr. Hersh disclaims beneficial ownership of the reported Common Units except to the extent of his pecuniary interest therein.

(10) Includes 4,359,553 Common Units held by McReynolds Energy Partners, L.P. and 2,521,570 Common Units held by McReynolds Equity Partners, L.P., which are limited partnerships, the general partners of which are owned by Mr. McReynolds. Mr. McReynolds disclaims beneficial ownership of the Common Units owned by McReynolds Energy Partners and McReynolds Equity Partners other than to the extent of his pecuniary interests therein.

(11) Includes 17,264,898 Common Units held by Kelcy Warren Partners, L.P., and 1,500,000 Common Units held by Kelcy Warren Partners, II, L.P., which are limited partnerships owned by Mr. Warren. Mr. Warren disclaims beneficial ownership of the Common Units owned by Kelcy Warren Partners and Kelcy Warren Partners II other than to the extent of his pecuniary interest therein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS,

AND DIRECTOR INDEPENDENCE

After the Parent Company s acquisition of the remaining 50% of the ETP incentive distribution rights on November 1, 2006 as discussed above, the Parent Company owns 100% of the Class A and Class B Limited Partner interests, and 100% of the General Partner interests in Energy Transfer Partners GP, L.P., the General Partner of ETP. The Parent Company s cash flows currently consist of distributions from ETP related to the following partnership interests, including incentive distribution rights in ETP:

- our ownership of the 2% General Partner interest in ETP, which we hold through our ownership interests in ETP GP;
- 62.5 million ETP Units, representing approximately 41% of the total outstanding ETP Common Units, which we hold directly; and
- 100% of the incentive distribution rights in ETP, which we likewise hold through our ownership interests in ETP GP and which entitle us to receive specified percentages of the cash distributed by ETP as ETP s per unit distribution increases.

ETP is required by its Partnership Agreement to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by the board of directors of its General Partner. Based on ETP s quarterly distribution of $0.89375 per unit for the three months ended December 31, 2008 and the number of its Common Units outstanding, the Parent Company would be entitled to receive a quarterly cash distribution of $139.8 million (or $559.2 million on an annualized basis), which consists of $4.6 million from our indirect ownership of the 2% General Partner interest in ETP, $79.3 million from our indirect ownership of 100% of the incentive distribution rights in ETP and $55.9 million from the Common Units of ETP that we currently own.

All of the current directors of LE GP, the Parent Company s general partner, are also directors of the general partner of ETP. In addition, Mr. Warren is also an executive officer of the general partner of ETP.

ET GP LLC, an entity controlled by Messrs. Davis and Warren will receive a $0.5 million per year management fee for the management of our operations and activities. Under the terms of a shared services agreement, ETE will also pay ETP an annual administrative fee of $0.5 million for the provision of various general and administrative services for ETE s benefit.

Our natural gas midstream operations secure compression services from third parties. Energy Transfer Technologies, Ltd. is one of the entities from which we obtain compression services. 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. ETP s Chief Executive Officer, Kelcy L. Warren has an indirect ownership interest in, and one of ETP s directors, Ted Collins, Jr. has an ownership interest in the ETG Entities. Ray C. Davis, one of our directors, had an ownership interest in the ETG Entities prior to June 1, 2007. In addition, Ted Collins, Jr., a director of ETP, and our President and Chief Financial Officer, 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 ETP s Audit Committee. During the year December 31, 2008, payments totaling $9.4 million were made to the ETG Entities for compression services provided to and utilized in our natural gas midstream operations.

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 ETP. Fees paid since the inception of this agreement were nominal.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following sets forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Audit fees (1)	$ 3,777,000	$ 2,172,000	$ 3,605,500
Audit related fees (2)	70,000	10,000	
Tax fees (3)			14,250
All other fees (4)		5,000	60,000
Total	$ 3,847,000	$ 2,187,000	$ 3,679,750

(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 for accounting-related matters that are reasonably related to the performance of our annual audit.
(3) Includes fees related to consultations regarding various publicly traded partnership income tax related practices.
(4) 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.

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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 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 100.

(2) Financial Statement Schedules - None.

(3) Exhibits - see Index to Exhibits set forth on page E-1.

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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 EQUITY, L.P.

By: LE GP, LLC,

its general partner

Date: February 27, 2009

By: /s/ John W. McReynolds
John W. McReynolds
President and Chief Financial 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/ John W. McReynolds John W. McReynolds	President and Chief Financial Officer (Principal Executive, Financial and Accounting Officer)	February 27, 2009
/s/ Kelcy L. Warren Kelcy L. Warren	Director and Chairman of the Board	February 27, 2009
/s/ David R. Albin David R. Albin	Director	February 27, 2009
/s/ Bill W. Byrne Bill W. Byrne	Director	February 27, 2009
/s/ Ray C. Davis Ray C. Davis	Director	February 27, 2009
/s/ Paul E. Glaske Paul E. Glaske	Director	February 27, 2009
/s/ John D. Harkey John D. Harkey	Director	February 27, 2009
/s/ Kenneth A. Hersh Kenneth A. Hersh	Director	February 27, 2009
/s/ K. Rick Turner K. Rick Turner	Director	February 27, 2009

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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	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
2.1	1-11727 (8-K/A)(9/26/08)	2.1	Contribution Agreement dated as of September 22, 2008 by and among Energy Transfer Partners, L.P. and OGE Energy Corp.
3.1	333-128097	3.1	Certificate of Conversion of Energy Transfer Company, L.P.
3.2	333-128097	3.2	Certificate of Limited Partnership of Energy Transfer Equity, L.P.
3.3	333-128097	3.3	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.3.1	1-32740 (10-K) (8/31/06)	3.3.1	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.3.2	1-32740 (8-K) (11/13/07)	3.3.2	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.4	333-128097	3.4	Certificate of Conversion of LE GP, LLC.
3.5	333-128097	3.5	Certificate of Formation of LE GP, LLC.
3.6	1-32740 (8-K) (5/7/07)	3.6.1	Amended and Restated Limited Liability Company Agreement of LE GP, LLC.
3.7	333-04018	3.1	Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
3.7.1	1-11727 (8-K) (8/23/00)	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.)
3.7.2	1-11727 (10K) (8/31/01)	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.)
3.7.3	1-11727 (10-Q) (5/31/02)	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.)
3.7.4	1-11727 (10-Q) (5/31/02)	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.)
3.7.5	1-11727 (10-Q) (2/29/04)	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.)

3.7.6	1-11727 (10-Q) (2/29/04)	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.)

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Exhibit Number	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
3.7.7	1-11727 (8-K) (3/16/05)	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.)
3.7.8	1-11727 (8-K) (2/9/06)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
3.7.9	1-11727 (8-K) (5/3/06)	3.1.9	Amendment No. 9 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
3.7.10	1-11727 (8-K) (11/3/06)	3.1.10	Amendment No. 10 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
3.7.11	1-11727 (8-K) (1/18/08)	3.1.11	Amended and Restated Amendment No. 11 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
3.7.12	1-11727 (8-K) (4/24/08)	3.1.12	Amendment No. 12 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
3.8	333-04018	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
3.8.1	1-11727 (10-K) (8/31/00)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
3.8.2	1-11727 (10-Q) (5/31/02)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
3.8.3	1-11727 (10-Q) (2/29/04)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P. (22)
3.9	1-11727 (10-Q) (2/29/04)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
3.10	1-11727 (10-Q) 2/28/02)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
3.11	1-11727 (10-Q) (5/31/07)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
3.12	1-11727 (10-Q) (5/31/07)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
3.13	333-128097	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.

3.13.1	333-128097	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
3.14	333-128097	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
4.1	1-11727 (8-K) (1/19/05)	4.1	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
4.2	1-11727 (8-K) (1/19/05)	4.2	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.

Exhibit Number	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
4.3	1-11727 (10-Q) (2/28/05)	10.45	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005.
4.4	1-11727 (10-Q) (2/28/05)	10.46	Notation of Guaranty.
4.5	1-11727 (8-K) (1/19/05)	4.3	Registration Rights Agreement dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers party thereto.
4.6	1-11727 (10-Q) (2/28/05)	10.39.1	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.
4.7	1-11727 (8-K) (8/2/05)	4.1	Third Supplemental Indenture dated 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.
4.8	1-11727 (8-K) (8/2/05)	4.2	Registration Rights Agreement dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein, and the initial purchasers party thereto.
4.9	1-11727 (10-K/A) (8/31/05)	4.9	Form of Senior Indenture of Energy Transfer Partners, L.P.
4.10	1-11727 (10-K/A) (8/31/05)	4.10	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
4.11	1-11727 (10-K) (8/31/06)	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.
4.12	1-11727 (8-K) (10/25/06)	4.1	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.
4.13	1-11727 (8-K) (3/28/08)	4.2	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
10.2	333-04018	10.2	Form of Note Purchase Agreement (June 25, 1996).
10.2.1	1-11727 (10-Q) (11/30/96)	10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
10.2.2	1-11727 (10-Q) (2/28/97)	10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
10.2.3	1-11727	10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.

	(10-K) (8/31/98)		
10.2.4	1-11727	10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
	(10-K) (8/31/99)		

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Exhibit Number	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
10.2.5	1-11727 (10-Q) (5/31/00)	10.16.3	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
10.2.6	1-11727 (8-K) (8/23/00)	10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
10.2.7	1-11727 (10-Q) (2/28/01)	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.
10.2.8	1-11727 (10-Q) (2/29/04)	10.2.8	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.
10.4.1**	1-11727 (10-Q) (2/28/02)	10.6.3	Heritage Propane Partners, L.P. (now known as Energy Transfer Partners, L.P.) Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
10.4.2**	1-11727 (10-Q) (6/30/08)	10.6.6	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan.
10.4.3**	1-11727 (8-K) (11/1/04)	10.1	Form of Grant Agreement.
10.5	1-11727 (10-Q) (5/31/98)	10.16	Note Purchase Agreement of Heritage Operating, L.P. dated as of November 19, 1997.
10.5.1	1-11727 (10-K) (8/31/98)	10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement of Heritage Operating, L.P.
10.5.2	1-11727 (10-K) (8/31/98)	10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement of Heritage Operating, L.P.
10.5.3	1-11727 (10-Q) (5/31/00)	10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement of Heritage Operating, L.P.
10.5.4	1-11727 (8-K) ((8/23/00)	10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement of Heritage Operating, L.P.
10.5.5	1-11727 (10-Q) (2/28/01)	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 of Heritage Operating, L.P.
10.5.6	1-11727 (10-Q) (2/29/04)	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 of Heritage Operating, L.P.

10.8	1-11727 (10-K) (8/31/01)	10.19	Note Purchase Agreement of Heritage Operating, L.P. dated as of August 10, 2000.

Exhibit Number	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
10.8.1	1-11727 (10-Q) (2/28/01)	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 of Heritage Operating, L.P.
10.8.2	1-11727 (10-Q) (5/31/01)	10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to August 10, 2000 Note Purchase Agreement of Heritage Operating, L.P.
10.8.3	1-11727 (10-Q) (2/29/04)	10.16.6	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 of Heritage Operating, L.P.
10.19	1-11727 (8-K) (2/1/05)	10.1	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 LaGrange Acquisition, L.P., as Buyer.
10.20	1-11727 (8-K) (2/1/05)	10.2	Cushion Gas Litigation Agreement dated January 26, 2005, among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and LaGrange 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.
10.21**	1-11727 (8-K) (3/3/2008)	10.1	Energy Transfer Partners, L.P. Midstream Bonus Plan.
10.21.1**	1-11727 (10-K) (8/31/06)	10.45	Energy Transfer Partners, L.P. Summary of Director Compensation.
10.22	1-11727 (8-K) (2/4/02)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.
10.23	1-11727 (10-Q) (2/29/04)	4.2	Unitholder Rights Agreement dated January 20, 2004, among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and LaGrange Energy, L.P.
10.24	333-128097	10.24	Registration Rights Agreement for Limited Partnership Units of LaGrange Energy, L.P.
10.25**	333-128097	10.25	Energy Transfer Equity Long-Term Incentive Plan.
10.26**	333-128097	10.26	Form of Director and Officer Indemnification Agreement.
10.27	1-11727 (8-K) (7/23/07)	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.

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Exhibit Number	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
10.29	1-32740 (8-K) (2/8/06)	10.2	Credit Agreement dated February 8, 2006, between Energy Transfer Equity, L.P. and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A. and Citicorp North America, Inc., as co-syndication agents, BNP Paribas and The Royal Bank of Scotland plc New York Branch, as co-documentation agents, Credit Suisse Cayman Islands Branch, Deutsche Bank AG New York Branch and UBS Loan Finance LLC, as senior managing agents, and Fortis Capital Corp, Suntrust Bank and Wells Fargo Bank, N.A., as managing agents.
10.34	1-32740 (10-K) (8/31/06)	10.34	First Amendment to Amended and Restated Credit Agreement, dated November 1, 2006, among Energy Transfer Equity, L.P., as the borrower, Wachovia Bank, National Association as administrative agent, UBS Loan Finance LLC, as syndication agent, BNP Paribas, Citicorp North America, Inc. and JPMorgan Chase Bank, N.A. as co-documentation agents, and UBS Securities LLC and Wachovia Capital Markets, LLC, as joint lead arrangers and joint book managers.
10.35	1-32740 (10-K) (8/31/06)	10.35	Contribution and Conveyance Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P., and Energy Transfer Partners, L.P.
10.36	1-32740 (10-K) (8/31/06)	10.36	Contribution, Assumption and Conveyance Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P., and Energy Transfer Investments, L.P.
10.37	1-11727 (8-K) (11/3/06)	3.1.10	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
10.38	1-32740 (10-K) (8/31/06)	10.38	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P. and Energy Transfer Investments, L.P.
10.39	1-11727 (8-K) (9/18/06)	10.1	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 Holding I LLC.
10.40	1-11727 (8-K) (9/18/06)	10.2	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
10.41	1-11727 (8-K) (9/18/06)	10.3	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
10.42	1-11727 (10-K) (8/31/06)	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.

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Exhibit Number	Previously Filed * With File Number (Form) (Period Ending or Date)	As Exhibit	
10.43	1-32740 (8-K) (11/30/06)		Registration Rights Agreement, dated November 27, 2006, by and among Energy Transfer Equity, L.P. and certain investors named therein.
10.44**	1-32740 (8-K) (12/26/06)		LE GP, LLC Outside Director Compensation Policy.
10.45	1-32740 (8-K) (3/5/07)		Registration Rights Agreement, dated March 2, 2007, by and among Energy Transfer Equity, L.P. and certain investors named therein.
10.46	1-32740 (8-K) (5/7/07)		Unitholder Rights and Restrictions Agreement, dated as of May 7, 2007, by and among Energy Transfer Equity, L.P., Ray C. Davis, Natural Gas Partners VI, L.P. and Enterprise GP Holdings, L.P.
10.47	1-11727 (10-Q) (5/31/07)		Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
10.47.1	1-11727 (10-Q) (5/31/07)		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.
10.48	1-11727 (10-Q) (5/31/07)		Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
21.1	1-32740 (10-Q 2/28/07)		List of Subsidiaries.
23.1			Consent of Grant Thornton LLP.
31.1			Certification of President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			Certification of President and 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 LE GP, LLC as of December 31, 2008.

* Incorporated herein by reference.
** Denotes a management contract or compensatory plan or arrangement.