Table of Contents

Index to Financial Statements

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 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219

(Address of principal executive offices and zip code)

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 $3,472,023,016. 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 159,002,471 Common Units outstanding.

Table of Contents

Index to Financial Statements

TABLE OF CONTENTS

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

ITEM 1. BUSINESS

Overview

We (Energy Transfer Partners, L.P., a Delaware limited partnership, ETP or the Partnership) are one of the three largest publicly traded master limited partnerships in the United States in terms of equity market capitalization (approximately $5.62 billion as of February 19, 2009). We are managed by our general partners, Energy Transfer Partners GP, L.P. (our General Partner), which is in turn managed by its general partner, Energy Transfer Partners, L.L.C. (ETP LLC). Energy Transfer Equity, L.P. (ETE) owns ETP LLC, the general partner of our General Partner. The activities in which we are engaged, all of which are in the United States, and the wholly-owned subsidiary operating partnerships (collectively referred to as the Operating Partnerships) through which we conduct those activities are as follows:

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

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

Significant 2008 Achievements

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

- Generated revenues of approximately $9.29 billion, operating income of approximately $1.12 billion and net income of approximately $866.0 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.

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

Table of Contents

Index to Financial Statements

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 Senior Notes in March 2008 and December 2008, respectively, and the issuance of 7,750,000 Common Units in July 2008. In addition, we subsequently raised $225.9 million in proceeds from the issuance of 6,900,000 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, we 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 Federal Energy Regulatory Commission s (FERC) National Environmental Policy Act (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. (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.

Tiger Pipeline

On January 27, 2009 we 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 our 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.

Table of Contents

Index to Financial Statements

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:

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

Table of Contents

Index to Financial Statements

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

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.

Table of Contents

Index to Financial Statements

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.

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.

Table of Contents

Index to Financial Statements

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;

- 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

Table of Contents

Index to Financial Statements

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).

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.

Table of Contents

Index to Financial Statements

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 our 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.

Table of Contents

Index to Financial Statements

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

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

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

We expect that acquisitions in natural gas operations will be the primary focus of our acquisition strategy going forward as evidenced by our acquisition of the Transwestern pipeline and Canyon Gathering System, although we 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 our public debt offering in December 2008 of $600.0 million aggregate principal amount of 9.70% Senior Notes due 2019 and our public equity offering in January 2009 of 6,900,000 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 through ownership of a substantial equity position in Energy Transfer Equity, L.P. (ETE), the entity that indirectly owns our General Partner and therefore benefits from incentive distribution payments we make to our General Partner.

Table of Contents

Index to Financial Statements

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.

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.

[Table of Contents](#)

[Index to Financial Statements](#)

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.

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.

Table of Contents

Index to Financial Statements

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 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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

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

Table of Contents

Index to Financial Statements

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.

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.

Table of Contents

Index to Financial Statements

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 9 to our consolidated financial statements), which provided 14.9% of our combined total propane supply during the year ended December 31, 2008.

Table of Contents

Index to Financial Statements

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 our 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.

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.

Table of Contents

Index to Financial Statements

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.

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

Table of Contents

Index to Financial Statements

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

22

Table of Contents

Index to Financial Statements

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

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

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

- the amount of natural gas transported through our transportation pipelines and gathering systems;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the price of natural gas;
- the relationship between natural gas and NGL prices;
- the weather in our operating areas;
- the cost to us of the propane we buy for resale and the prices we receive for our propane;
- the level of competition from other midstream companies, interstate pipeline companies, propane companies and other energy providers;
- the level of our operating costs;

prevailing economic conditions; and

the level of our hedging activities.

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

the level of capital expenditures we make;

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

the cost of acquisitions, if any;

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

our debt service requirements;

fluctuations in our working capital needs;

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

Table of Contents

Index to Financial Statements

- our ability to access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount, if any, of cash reserves established by our General Partner in its discretion for the proper conduct of our business.

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

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

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

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

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

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

As of December 31, 2008, ETE owned 62,500,797 Common Units. ETE owns our General Partner. If ETE were to sell and/or distribute its Common Units to the holders of its equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of our outstanding Common Units.

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

As of December 31, 2008, we had approximately $5.66 billion of consolidated debt outstanding. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;

covenants contained in our existing debt arrangements require us to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

we may be at a competitive disadvantage relative to similar companies that have less debt;

we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level; and

failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability of our subsidiaries to incur additional debt and our ability to pay our distributions. We are required to measure these financial tests and covenants quarterly and, as of 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 us on acceptable terms, or at all.

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

As of December 31, 2008, we had approximately $5.66 billion of consolidated debt outstanding. A significant increase in our indebtedness that is proportionately greater than our issuances of equity could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our 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 $5.66 billion of consolidated debt, of which approximately $4.75 billion was at fixed interest rates and approximately $0.91 billion was at variable interest rates. We have entered interest rate swaps for a total notional amount of $125.0 million, resulting in a net amount of $787.0 million of variable-rate debt at December 31, 2008. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements. To the extent that we have debt with variable interest rates that is not hedged, our results of operations, cash flows and financial condition, could be materially adversely affected by significant increases in interest rates. During the three months ended December 31, 2008, the Partnership 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 our results of operations until the forecasted debt is issued and could require a cash payment upon settlement.

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

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

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

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

Table of Contents

Index to Financial Statements

Furthermore, if the Unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. The General Partner generally may not be removed except upon the vote of the holders of 66 $^{2}/_{3}$% of the outstanding units voting together as a single class, including units owned by the General Partner and its affiliates. As of December 31, 2008, ETE and its affiliates held approximately 41% of our outstanding units, with approximately 1% of units held by our officers and directors. Consequently, it could be difficult to remove the General Partner without the consent of the General Partner and our affiliates.

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

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

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

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

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

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

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

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

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

Unitholders may have liability to repay distributions.

Under certain circumstances Unitholders may have to repay us amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to you if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated Delaware law, will be liable to the limited partnership for the distribution amount for three years from the distribution date. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to him at the time he or she became a limited partner if the liabilities could not be determined from the partnership agreement.

Table of Contents

Index to Financial Statements

Risks Related to Conflicts of Interest

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

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

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

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

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

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

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

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

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

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

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

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

As of December 31, 2008, ETE and its affiliates directly and indirectly owned an aggregate limited partner interest in us of approximately 41% and our officers and directors owned approximately 1% of the limited partner interests in us. Conflicts of interest could arise in the future as a result of relationships between our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our

General Partner may favor its own interests and those of its affiliates over the interests of the Unitholders. The nature of these conflicts includes the following considerations:

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

27

Table of Contents

Index to Financial Statements

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

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

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

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

Our General Partner determines which costs are reimbursable by us.

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

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

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

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

Affiliates of our General Partner are not prohibited from competing with 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 LE GP, the general partner of ETE. 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.

Risks Related to Our Business

We may not be able to obtain funding on acceptable terms or at all under our revolving credit facility or otherwise because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our 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, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be required to post collateral to support our obligations. Moreover, without adequate funding, we may be unable to execute our 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 our revenues and results of operations.

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

Many of our 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 our 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

Table of Contents

Index to Financial Statements

financing may result in a significant reduction in our customers spending for natural gas drilling activity, which could result in lower volumes being transported on our pipeline systems. For example, a number of our customers have announced reduced drilling capital expenditure budgets for 2009. A significant reduction in drilling activity could have a material adverse effect on our operations.

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

The risks of nonpayment and nonperformance by our customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. 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 our customers. Any substantial increase in the nonpayment and nonperformance by our customers could have a material effect on our results of operations and operating cash flows.

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

On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Our 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, we 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, our 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 our operating income for our 2008 year. If the FERC is successful in revoking our blanket marketing authority, our 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 our own production, and any other sales of natural gas by us would be required to be made at contract prices that would be subject to individual FERC approval.

In its Order and Notice, the FERC specified that it was 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 our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. 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 the 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

Table of Contents

Index to Financial Statements

the FERC to a federal district court for *de novo* review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis s 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 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 decisions due by May 11, 2009, however, as discussed below, we 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 judges 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 our 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. We 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 our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC holds substantial enforcement authority. At this time, we are unable 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 (CEA) by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, we entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, we agreed to pay the CFTC $10.0 million and the CFTC agreed to release us and our affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that we are 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, we 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 ETE 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 ETE 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

30

Table of Contents

Index to Financial Statements

suits against us and ETE contains an additional allegation that we and ETE transported gas in a manner that favored our 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 producer/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 us in the United States District Court for the Southern District of Texas. This action alleges that we 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, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us 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, we 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, we filed a motion to dismiss the complaint. On June 19, 2008, the plaintiffs filed a response opposing our motion to dismiss. We filed a reply in support of our motion on July 9, 2008.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we 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 we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our 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, we filed a motion to dismiss this complaint. On July 2, 2008 the plaintiffs filed a response opposing our motion to dismiss. We 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 our 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 our control and have been volatile.

Table of Contents

Index to Financial Statements

Income from our 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 our HPL System, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize 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, we enter into percentage-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers. Under percentage-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our results of operations. Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs if we are not able to bypass our processing plants and sell the unprocessed natural gas. Under processing fee agreements, we process the gas for a fee. If recoveries are less than those guaranteed the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole with regard to contractual recoveries.

In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, during our 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 our average NGLs composition during our year ended December 31, 2008 ranged from a high of approximately $1.96 per gallon to a low of approximately $0.66 per gallon.

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

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

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;

- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

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

Table of Contents

Index to Financial Statements

From time to time, we have sought to limit a portion of the adverse effects resulting from changes in natural gas and other commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms. To the extent that we hedge our commodity price and interest rate exposures, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, our 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 our physical or financial positions, or hedging policies and procedures are not followed.

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

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

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity and production generally decrease as oil and natural gas prices decrease. We have no control over the level of drilling activity in our areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline, sometimes referred to as the decline rate. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. 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 our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. Accordingly, our cash flows will also decline unless we are able to access new supplies of natural gas by connecting additional production to these systems.

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

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

[Table of Contents](#)

[Index to Financial Statements](#)

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

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

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

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

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

At December 31, 2008, our consolidated balance sheet reflected $743.7 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.

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

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

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

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

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

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;

decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;

significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;

Table of Contents

Index to Financial Statements

- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;
- less effectively manage our historical assets, due to the diversion of management s attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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

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

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

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

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

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

One of the ways that we have grown our business is through the construction of additions to our existing gathering, compression, treating, processing and transportation systems. The construction of a new pipeline or the expansion of an existing pipeline, by adding additional compression capabilities or by adding a second pipeline along an existing pipeline, and the construction of new processing or treating facilities, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital that we will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost. We currently have 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 our 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 our results of operations and cash flows. Moreover, our revenues may not increase immediately following the completion of particular projects. For instance, if we build a new pipeline, the construction will occur over an extended period of time, but we may not materially increase our revenues until long after the project s completion. 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 our ability to obtain commitments from producers in this area to utilize the newly constructed pipelines. In this regard, we 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 our expected investment return, which could adversely affect our results of operations and financial condition.

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

Table of Contents

Index to Financial Statements

For our year ended December 31, 2008, XTO Energy Inc., EnCana Oil and Gas (USA), Inc., Sandridge Energy Inc., and ConocoPhillips Company supplied us with approximately 75% of the Southeast Texas System s natural gas supply. For our year ended December 31, 2008, XTO Energy Inc., Chesapeake Energy Marketing, Inc., EnCana Oil and Gas (USA), Inc. and EOG Resources, Inc. supplied us with approximately 75% of the North Texas System s natural gas supply. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

We depend on key customers to transport natural gas through our pipelines.

We have 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 our ET Fuel System. We also have an eight-year fee-based transportation contract with TXU Portfolio Management Company, L.P., a subsidiary of TXU Corp., which we refer to as TXU Shipper, to transport natural gas on the ET Fuel System to TXU s electric generating power plants. We have also entered into two eight-year natural gas storage contracts 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 our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

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 our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

With respect to our 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 our Tiger pipeline project, we have 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 our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

Federal, state or local regulatory measures could adversely affect the business and operations of our midstream and intrastate assets.

Our midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects our business and the market for our products. The rates, terms and conditions of some of the transportation and storage services we provide on the HPL System, the East Texas pipeline, the Oasis pipeline and the ET Fuel System are subject to FERC regulation under Section 311 of the Natural Gas Policy Act, or NGPA. Under Section 311, rates charged for transportation and storage must be fair and equitable amounts. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline s statement of operating conditions, are subject to FERC review and approval. Should FERC determine not to authorize rates equal to or greater than our currently approved rates we may suffer a loss of revenue. Failure to observe the service limitations applicable to storage and transportation service under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline s FERC-approved statement of operating conditions could result in an alteration of jurisdictional status and/or the imposition of administrative, civil and criminal penalties.

Our intrastate transportation and storage operations are subject to state regulation in Texas, New Mexico, Arizona, Louisiana, Utah and Colorado, the states in which we operate these types of natural gas facilities. Our intrastate transportation operations located in

Table of Contents

Index to Financial Statements

Texas are subject to regulation as common purchasers and as gas utilities by the Texas Railroad Commission, or TRRC. The TRRC s jurisdiction extends to both rates and pipeline safety. The rates we charge for transportation and storage services are deemed just and reasonable under Texas law unless challenged in a complaint. Should a complaint be filed or should regulation become more active, our business may be adversely affected.

Our midstream and intrastate transportation operations are also subject to ratable take and common purchaser statutes in Texas, New Mexico, Arizona, Louisiana, Utah and Colorado. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. Other state and local regulations also affect our business.

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

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

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

Our 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 our 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. We also may be limited by the terms of negotiated rate agreements from seeking future rate increases, or constrained by competitive factors from charging our 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.

Table of Contents

Index to Financial Statements

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 we 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 our interstate natural gas companies could reduce our revenues associated with providing transportation services on a prospective basis. We cannot assure you that our 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 us, to include an allowance for income taxes in their regulated rates has been subject to extensive litigation before FERC and the courts, and the FERC s current policy is subject to future refinement or change.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before FERC and the courts for a number of years. 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, we thus remain eligible to include an income tax allowance in the tariff rates we charge 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 our tariff rates is generally not subject to challenge prior to the expiration of our settlement agreement in 2011.

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 our 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 our interstate pipelines to compete for business, may impair their ability to recover costs, or may increase the cost and burden of operation.

We must on occasion rely upon rulings by FERC or other governmental authorities to carry out certain of our business plans. For example, in order to carry out our plan to construct the Fayetteville Express pipeline we 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 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.

Table of Contents

Index to Financial Statements

Similarly, we were 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 us such certificate authority, there are pending requests for clarification and rehearing of that order. We cannot guarantee that FERC will, on rehearing, reaffirm in all materials respects its July 25, 2008 Midcontinent Express certificate order. Nor can we 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 cannot give any assurance regarding the likely future regulations under which we will operate our interstate pipelines or the effect such regulation could have on our business, financial condition, and results of operations.

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

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

We may incur substantial environmental costs and liabilities because of the underlying risk inherent to our 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 our properties and facilities, many of which have been used for industrial activities for a number of years, even if such discharges were caused by our predecessors. Private parties, including the owners of properties through which our gathering systems pass or facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. The total accrued future estimated cost of remediation activities relating to our Transwestern pipeline operations is approximately $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, we could be required to purchase and surrender 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.

Table of Contents

Index to Financial Statements

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.

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

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

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

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

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

The 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.

Table of Contents

Index to Financial Statements

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

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

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

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

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

Because of our ownership of the Oasis pipeline and ET Fuel System, we can generally elect to bypass our 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 we do not have a sufficient amount of lean gas to blend with the volume of rich gas that we receive at the processing plant, we may have to process the rich gas. If we have to process when processing margins are unfavorable, our results of operations will be adversely affected.

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

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

For our year ended December 31, 2008, approximately 27.3% of our sales of natural gas were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are increasingly reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

Table of Contents

Index to Financial Statements

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

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

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

Our operations are subject to regulation by the U.S Department of Transportation (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 our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements for its existing transportation assets other than the Transwestern pipeline will result in capital costs of $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, we estimate that we will incur pipeline integrity capital costs of $8.9 million, as well as operating and maintenance costs of $1.7 million, with respect to our 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 us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

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

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

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

Table of Contents

Index to Financial Statements

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

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

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

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

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

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

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

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

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

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

Table of Contents

Index to Financial Statements

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

During 2008, we purchased approximately 50.7%, 15.0% and 14.9% of our 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 the general partner of ETE. Titan purchases substantially all of its propane from Enterprise pursuant to an agreement that expires in 2010. If supplies from these sources were interrupted, the cost of procuring replacement supplies and transporting those supplies from alternative locations might be materially higher and, at least on a short-term basis, margins could be adversely affected. Supply from Canada is subject to the additional risk of disruption associated with foreign trade such as trade restrictions, shipping delays and political, regulatory and economic instability.

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

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

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

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

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

Tax Risks to Common Unitholders

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

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

Table of Contents

Index to Financial Statements

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, 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 are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our Common Units.

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

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

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

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

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

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

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

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

Tax-exempt entities and 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.

Table of Contents

Index to Financial Statements

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.

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

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

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

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.

Table of Contents

Index to Financial Statements

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

We will be considered terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our termination would, among other things, result in the closing of our taxable year which would require us to file two tax returns (and could result in our unitholders receiving two Schedules K-1) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred.

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

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

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.

Table of Contents

Index to Financial Statements

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. HOLP s customer storage tanks are pledged as collateral to secure the obligations of HOLP to its banks and the holders of its notes.

We utilize a variety of trademarks and trade names in our propane operations that we own or have secured the right to use, including Heritage Propane, 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, 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.

For a description of legal proceedings, see note 10 to our consolidated financial statements.

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

On December 16, 2008, we held a special meeting of our Unitholders of record as of November 21, 2008. At the meeting, our Unitholders voted on and approved the ETP 2008 Long-Term Incentive Plan (the 2008 Incentive Plan). The 2008 Incentive Plan provides for awards of options to purchase our Common Units, awards of our restricted units, awards of our phantom units, awards of our Common Units, awards of distribution equivalent rights, or DERs, awards of common unit appreciation rights, and other unit-based awards to employees of ETP, our General Partner, and the general partner of our General Partner, a subsidiary or their

Table of Contents

Index to Financial Statements

affiliates, and members of the board of directors of the general partner of our General Partner, which we refer to as our Board of Directors. Subject to adjustment as provided in the 2008 Incentive Plan, up to 5,000,000 of our Common Units may be granted to plan participants as awards. See Note 7 to our consolidated financial statements.

The holders of a total of 107,245,669 Common Units, representing 66.66% of the total units issued and outstanding and entitled to vote, were present in person or by proxy at the special meeting, constituting a quorum. At the meeting, the votes cast for and against, and those abstaining from voting with respect to the proposal to approve the terms of the 2008 Incentive Plan, were as follows:

For	101,350,910
Against	5,336,683
Abstain	558,076
Broker and Other Non-Votes	53,630,308

PART II

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

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

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

	Price Range		Cash
	High	Low	Distribution (1)
Fiscal Year 2008			
Fourth Quarter Ended December 31, 2008	$ 40.00	$ 22.40	$ 0.89375
Third Quarter Ended September 30, 2008	$ 45.29	$ 28.61	$ 0.89375
Second Quarter Ended June 30, 2008	$ 51.12	$ 42.32	$ 0.89375
First Quarter Ended March 31, 2008	$ 54.56	$ 43.58	$ 0.86875
Transition Period			
Four Months Ended December 31, 2007 (2)	$ 55.87	$ 47.62	$ 1.12500
Fiscal Year 2007			
Fourth Quarter Ended August 31, 2007	$ 64.00	$ 40.50	$ 0.82500
Third Quarter Ended May 31, 2007	$ 63.40	$ 54.76	$ 0.80625
Second Quarter Ended February 28, 2007	$ 56.00	$ 49.23	$ 0.78750
First Quarter Ended November 30, 2006	$ 54.64	$ 43.60	$ 0.76875

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(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 45 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 14, 2008.

Table of Contents

Index to Financial Statements

Description of Units

As of January 31, 2009, there were approximately 147,704 individual Common Unitholders, which includes Common Units held in street name. Our Common Units represent limited partner interests in our Amended and Restated Agreement of Limited Partnership, as amended to date (the Partnership Agreement) that entitle the holders to the rights and privileges specified in the Partnership Agreement.

Common Units. As of December 31, 2008, we had 152,102,471 Common Units outstanding, of which 88,863,787 were held by the public, 62,500,797 were held by ETE or its affiliates and 737,887 were held by our officers and directors. As of such date, the Common Units represent an aggregate 98.0% limited partner interest in us. Our General Partner owns an aggregate 2.0% general partner interest in us. Our Common Units are registered under the Securities Exchange Act of 1934, as amended and are listed for trading on the New York Stock Exchange (the NYSE). The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

Class E Units. In conjunction with our purchase of the capital stock of Heritage Holdings Inc. (HHI) in January 2004, there are currently 8,853,832 Class E Units outstanding, all of which are owned by HHI, our wholly-owned subsidiary. The Class E Units generally do not have any voting rights. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. Management plans to leave the Class E Units outstanding indefinitely.

Incentive Distribution Rights. Incentive Distribution Rights represent the contractual right to receive a specified percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read Distributions of Available Cash from Operating Surplus below.

Cash Distribution Policy

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

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

- Less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law or and debt instrument or other agreement (including reserves for future capital expenditures and for our future capital needs); or
  - provide funds for distributions to Unitholders and our General Partner in respect of any one or more of the next four quarters.
- Plus all cash on hand on the date of determination of Available Cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facilities and in all cases are used solely for working capital purposes or to pay distributions to partners.

Available Cash is more fully defined in our Partnership Agreement which is an exhibit to this report.

Operating Surplus and Capital Surplus

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

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

our cash balance on the closing date of our initial public offering in 1996; plus

$10.0 million (as described below); plus

Table of Contents

Index to Financial Statements

all of our cash receipts since the closing of our initial public offering, excluding cash from interim capital transactions such as borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus

our working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less

all of our operating expenditures after the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less

the amount of our cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

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

borrowings other than working capital borrowings;

sales of our debt and equity securities; and

sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

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

Distributions of Available Cash from Operating Surplus

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

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

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

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

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

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

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

Distributions of Available Cash from Capital Surplus

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

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

Table of Contents

Index to Financial Statements

Thereafter, we will make all distributions of available cash from capital surplus as if they were from operating surplus. Our Partnership Agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price per Common Unit less any distributions of capital surplus per unit is referred to as the unrecovered capital .

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

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

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

The total amount of distributions declared are reflected in Note 6 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

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.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Units Purchased(1)	(b) Average Price Paid per Unit	(c) Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Purchased Under the Plans or Programs
Month #1 (October 1 October 31, 2008)	69,000	$ 35.28	N/A	N/A
Month #2 (November 1 November 30, 2008)			N/A	N/A
Month #3 (December 1 December 31, 2008)	21,556	$ 30.71	N/A	N/A
Total	90,556	$ 34.14	N/A	N/A

(1) Pursuant to the terms of our equity incentive plans, to the extent the Partnership is required to withhold federal, state, local or foreign taxes in connection with any grant of an award, the issuance of Common Units upon the vesting of an award, or payment

Table of Contents

Index to Financial Statements

made to a plan participant, it is a condition to the receipt of such payment that the plan participant make arrangements satisfactory to the Partnership for the payment of taxes. A plan participant may relinquish a portion of the Common Units to which the participant is entitled in connection with the issuance of Common Units upon vesting of an award as payment for such taxes. During the three months ended December 31, 2008, certain of the participants in the 2004 Unit Plan elected to have a portion of the Common Units to which they were entitled upon vesting of restricted units withheld by the Partnership to satisfy the Partnership s tax withholding obligations. None of the Common Units delivered to recipients of unit awards upon vesting were purchased by the Partnership through a publicly announced open-market plan or program.

ITEM 6. SELECTED FINANCIAL DATA

In January 2004, we combined the natural gas midstream and transportation operations of ETC OLP with the retail propane operations of Heritage Propane Partners, L.P. (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.

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 Partners, L.P. included elsewhere in this report and with Management s Discussion and Analysis of Financial Condition and Results of Operations included in this report. The amounts in the table below, except per unit data, are in thousands.

Table of Contents

Index to Financial Statements

	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	16,702	6,060	121,278	102,028	75,700	30,810
Total revenues	9,293,868	2,349,510	6,792,037	7,859,096	6,168,798	2,346,957
Gross margin	2,355,788	675,856	1,713,831	1,290,780	787,283	365,533
Depreciation and amortization	262,151	71,333	179,162	117,415	92,943	48,599
Operating income	1,117,579	323,634	829,652	642,871	312,051	139,089
Interest expense, net of interest capitalized	(265,701)	66,298	175,563	113,857	93,017	41,190
Income from continuing operations before income tax expense	872,703	272,613	689,797	541,772	208,678	97,470
Income tax expense (a)	6,680	10,789	13,658	25,920	7,295	4,481
Income from continuing operations	866,023	261,824	676,139	515,852	201,383	92,989
Basic income from continuing operations per unit (b)	3.75	1.22	3.32	3.16	1.51	1.62
Diluted income from continuing operations per limited partner unit (b)	3.74	1.21	3.31	3.15	1.50	1.62
Cash distribution per unit (c)	3.55	1.13	3.19	2.56	1.89	1.46
Balance Sheet Data (at period end):						
Current assets	1,183,401	1,409,959	1,041,093	1,301,804	1,446,572	480,435
Total assets	10,627,489	9,008,161	7,708,428	5,455,013	4,415,458	2,327,104
Current liabilities	1,150,547	1,215,461	924,217	1,016,490	1,239,426	397,037
Long-term debt, less current maturities	5,618,549	4,297,264	3,626,977	2,589,124	1,675,705	1,070,871
Partners capital/Stockholders equity	3,743,069	3,379,191	3,039,833	1,736,862	1,326,192	746,980
Other Financial Data:						
Cash flow provided by operating activities	1,258,145	245,702	1,112,732	543,884	169,418	162,695
Cash flow used in investing activities	(2,015,585)	(995,943)	(2,158,090)	(1,244,406)	(1,133,749)	(790,737)
Cash flow provided by financing activities	792,875	738,003	1,088,022	701,649	907,500	656,665
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	681,835

(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.

(c) The cash distribution per unit for fiscal year 2006 includes the special SCANA distribution of $0.0325 per unit discussed in Note 6 of our consolidated financial statements.

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

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

Table of Contents

Index to Financial Statements

Overview

General

Our primary objective is to increase the level of our cash distributions over time by pursuing a business strategy that is currently focused on growing our natural gas midstream and 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

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

For the year ended December 31, 2008, our gross margin was $2.36 billion and operating income was $1.12 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.

Table of Contents

Index to Financial Statements

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, we 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). We also received net proceeds of approximately $373.0 million from the sale of our 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 our revolving credit facility (the ETP Credit Facility).

On January 27, 2009, we closed a public offering of 6,900,000 Common Units representing limited partner interests at $34.05 per Common Unit. We used the net proceeds from the offering to repay approximately $225.9 million outstanding debt under the ETP Credit Facility. We expect 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. We also successfully completed a $600.0 million senior note offering in December 2008 and a 6.9 million 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 ETP Credit Facility of $1.04 billion. On a pro forma basis, as of December 31, 2008, taking into account net proceeds of approximately $225.9 million from our 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.

We will continue to evaluate a variety of financing sources in order to fund our 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, we have initiated discussions with ETE regarding the prospect of ETE purchasing additional Common Units from us. ETE has an aggregate of approximately $378.4 million of cash on hand and available borrowing capacity under its 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, we ceased our speculative trading activities in July 2008. As a result, we 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.

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

Consolidated Results

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Revenues	$ 9,293,868	$ 6,792,037	$ 2,501,831
Cost of products sold	6,938,080	5,078,206	1,859,874
Gross margin	2,355,788	1,713,831	641,957
Operating expenses	781,831	559,600	222,231
Depreciation and amortization	262,151	179,162	82,989
Selling, general and administrative	194,227	145,417	48,810
Operating income	1,117,579	829,652	287,927
Interest expense, net of interest capitalized	(265,701)	(175,563)	(90,138)
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	(50,989)	31,032	(82,021)
Allowance for equity funds used during construction	63,976	4,948	59,028
Other, net	9,306	2,019	7,287
Income tax expense	(6,680)	(13,658)	6,978
Minority interests		(1,142)	1,142
Net income	$ 866,023	$ 676,139	$ 189,884

See the detailed discussion of revenues, costs 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.

Gains (Losses) on Non Hedged Interest Rate Derivatives. The Partnership had interest rate swaps with a notional amount of $625.0 million outstanding at December 31, 2008 compared to $125.0 million outstanding at August 31, 2007. The losses during the year ended December 31, 2008 primarily relate to changes in the fair value of forward starting interest rate swaps that were not designated as hedges under SFAS 133 as a result of a sharp decline in the 10 year LIBOR swap rate. The comparable period ended August 31, 2007 had settlement gains of $31.5 million on forward starting swaps due to increased in the 10 year LIBOR rate during the period.

Table of Contents

Index to Financial Statements

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 8 to our consolidated financial statements.

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	$ 166,414	$ 123,176	$ 43,238
Intrastate Transportation and Storage	718,348	488,098	230,250
Interstate Transportation	124,676	95,650	29,026
Retail Propane	114,564	124,263	(9,699)
Other	(1,531)	1,735	(3,266)
Unallocated selling, general and administrative expenses	(4,892)	(3,270)	(1,622)
Operating income	$ 1,117,579	$ 829,652	$ 287,927

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.

59

Table of Contents

Index to Financial Statements

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	59,344	23,388	35,956
Selling, general and administrative	47,268	35,597	11,671
Segment operating income	$ 166,414	$ 123,176	$ 43,238

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.

Table of Contents

Index to Financial Statements

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	84,701	56,145	28,556
Selling, general and administrative	76,488	52,844	23,644
Segment operating income	$ 718,348	$ 488,098	$ 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;

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 periods 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.

Table of Contents

Index to Financial Statements

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.

Retail Propane

	Year Ended December 31, 2008	Year Ended August 31, 2007	Amount of Change
Retail propane gallons (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

Table of Contents

Index to Financial Statements

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.

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.

Table of Contents

Index to Financial Statements

Consolidated Results

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Amount of Change
Revenues	$ 2,349,510	$ 2,162,466	$ 187,044
Cost of products sold	1,673,654	1,689,843	(16,189)
Gross margin	675,856	472,623	203,233
Operating expenses	221,757	173,365	48,392
Depreciation and amortization	71,333	48,767	22,566
Selling, general and administrative	59,132	40,603	18,529
Operating income	323,634	209,888	113,746
Interest expense, net of interest capitalized	(66,298)	(54,946)	(11,352)
Equity in earnings (losses) of affiliates	(94)	4,743	(4,837)
Gain on disposal of assets	14,310	2,212	12,098
Other, net	1,061	2,158	(1,097)
Income tax expense	(10,789)	(3,120)	(7,669)
Minority interests		(490)	490
Net income	$ 261,824	$ 160,445	$ 101,379

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

Interest Expense. Interest expense increased $11.4 million principally due to a net $13.8 million increase in interest expense related to increased borrowings from our 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, 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.

Table of Contents

Index to Financial Statements

Segment Operating Results

Operating income by segment is as follows:

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Amount of Change
Midstream	$ 73,167	$ 41,735	$ 31,432
Intrastate Transportation and Storage	172,120	112,021	60,099
Interstate Transportation	29,657	11,854	17,803
Retail Propane	46,747	49,841	(3,094)
Other	(628)	528	(1,156)
Unallocated selling, general and administrative expenses	2,571	(6,091)	8,662
Operating income	$ 323,634	$ 209,888	$ 113,746

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 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	Four Months Ended December 31, 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	13,629	6,434	7,195
Selling, general and administrative	18,693	5,952	12,741
Segment operating income	$ 73,167	$ 41,735	$ 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;

Table of Contents

Index to Financial Statements

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, 2007	Four Months Ended December 31, 2006	Amount of 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	20,670	16,261	4,409
Selling, general and administrative	20,615	16,626	3,989
Segment operating income	$ 172,120	$ 112,021	$ 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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

Retail Propane

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006	Amount of Change
Retail propane gallons (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)

Table of Contents

Index to Financial Statements

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	179,162	117,415	61,747
Selling, general and administrative	145,417	107,505	37,912
Operating income	829,652	642,871	186,781
Interest expense, net of interest capitalized	(175,563)	(113,857)	(61,706)
Equity in earnings (losses) of affiliates	5,161	(479)	5,640
Gain (loss) on disposal of assets	(6,310)	851	(7,161)
Other, net	37,999	14,620	23,379
Income tax expense	(13,658)	(25,920)	12,262
Minority interests	(1,142)	(2,234)	1,092
Net income	$ 676,139	$ 515,852	$ 160,287

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 $51.2 million increase in interest expense related to borrowings from our 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 gains of $0.3 million on interest rate swaps were recorded as a reduction to interest expense. Such gains were not recognized in interest expense in the year ended August 31, 2007; rather, such gains are included in interest and other income. Hedge ineffectiveness charges increased interest expense by $1.8 million in fiscal 2007, compared to gains of $0.8 million in fiscal 2006. See Note 11 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.

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, net 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 6 of our consolidated financial statements for further detail).

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

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

Table of Contents

Index to Financial Statements

Segment Operating Results

Operating income by segment is as follows:

	Years Ended August 31, 2007	2006	Amount of Change
Midstream	$ 123,176	$ 151,507	$ (28,331)
Intrastate Transportation and Storage	488,098	430,698	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	(3,270)	(17,288)	14,018
Operating income	$ 829,652	$ 642,871	$ 186,781

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.

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	17,907	10,425	7,482
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	23,388	15,744	7,644
Selling, general and administrative	35,597	23,922	11,675
Segment operating income	$ 123,176	$ 151,507	$ (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

Table of Contents

Index to Financial Statements

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.

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	56,145	42,477	13,668
Selling, general and administrative	52,844	46,520	6,324
Segment operating income	$ 488,098	$ 430,698	$ 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;

Table of Contents

Index to Financial Statements

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.

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.

Table of Contents

Index to Financial Statements

Retail Propane

	Years Ended August 31, 2007	2006	Amount of Change
Retail propane gallons (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.

Operating Expenses. The increase in operating expenses between the 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.

Table of Contents

Index to Financial Statements

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. This termination did not affect our classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income for federal income tax purposes. This termination required us to close our taxable year, make new elections as to various tax matters and reset the depreciation schedule for our depreciable assets for federal income tax purposes. The resetting of our depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to our Unitholders. However, certain elections we made in connection with this tax termination allowed us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of our Unitholders, which deductions had not previously been utilized in computing taxable income allocable to our Unitholders.

As a result of the tax termination discussed above, we elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our wholly-owned subsidiary, HHI, which owns our Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of our Common Units. The amount of such goodwill accumulated as of the date of our acquisition of HHI (approximately $158 million) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. We account for HHI using the treasury stock method due to its ownership of our Class E units. Due to the accounting rules outlined in SFAS 109 and related Interpretations, we account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of our HHI purchase price allocation, which effectively results in a charge to our common equity and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the year ended 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	2006
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	1.25%	1.82%	1.25%	3.10%
Earnings not subject to tax at the Partnership level	(35.48)%	(32.86)%	(34.25)%	(33.30)%
Effective tax rate	0.77%	3.96%	2.00%	4.80%

Table of Contents

Index to Financial Statements

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	2006
Current provision:				
Federal	$ (180)	$ 2,990	$ 7,896	$ 27,640
State	12,216	5,705	9,803	1,994
Total	12,036	8,695	17,699	29,634
Deferred provision:				
Federal	(5,634)	1,482	(4,598)	(3,329)
State	278	612	557	(385)
Total	(5,356)	2,094	(4,041)	(3,714)
Total Tax Provision	$ 6,680	$ 10,789	$ 13,658	$ 25,920

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

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

We currently believe that our 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;

Table of Contents

Index to Financial Statements

- 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.

We generally fund our 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 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 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. We have also recently increased the available capacity under the ETP Credit Facility by using aggregate proceeds of approximately $821.9 million from our December 2008 Senior Notes and January 2009 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 ETP Credit Facility of 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). 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.

We will continue to evaluate a variety of financing sources in order to fund our 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, we have initiated discussions with ETE regarding the prospect of ETE purchasing additional Common Units from us. ETE has an aggregate of approximately $378.4 million of cash on hand and available borrowing capacity under its 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 and 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.

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

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

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

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 $1.26 billion as compared to cash provided by operating activities of $1.11 billion 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 $317.2 million (principally depreciation and amortization and unit-based compensation expense) and changes in operating assets and liabilities of $75.0 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 $792.9 million for the year ended December 31, 2008. We received $373.0 million in net proceeds from equity offerings (see Note 6 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 5 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 $879.2 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, we 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 our 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, we 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, we 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 our general partner to maintain its 2% general partner s interest, were used to repay outstanding borrowings under the ETP Credit Facility.

Table of Contents

Index to Financial Statements

In December 2008, we 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.

On January 27, 2009, we 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 repay outstanding borrowings under the ETP Credit Facility.

Description of Indebtedness

Our indebtedness as of December 31, 2008 consisted 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. We also have separate indebtedness at Transwestern and HOLP. The terms of our indebtedness and that of our Operating Partnerships are described in more detail below and in Note 5 to our consolidated financial statements. Failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability of our subsidiaries to incur additional debt and our ability to pay our distributions. We are required to measure these financial tests and covenants quarterly and, as of 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.

ETP 9.70% Senior Notes

In December 2008, we completed a public offering of $600.0 million aggregate principal amount of our 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. 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, we 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). We 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 our $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 we 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 any of our subsidiaries.

Table of Contents

Index to Financial Statements

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 our 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 the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership s subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern 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%.

Table of Contents

Index to Financial Statements

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.

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.

Table of Contents

Index to Financial Statements

MEP previously had a $197.0 million reimbursement agreement under which MEP could issue letters of credit. This reimbursement agreement expired in 2008 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 and indentures 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;
- 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 ETP GP with respect to ETP s Common Units.

Table of Contents

Index to Financial Statements

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 the Partnership s, Transwestern s and HOLP s debt agreements as of December 31, 2008. We have 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). We plan to fund our 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 our senior notes, borrowings under the ETP Credit Facility and/or proceeds from the sale of 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 us on acceptable terms, or at all. While we expect that our 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 us to satisfy the financial ratio covenants related to our existing debt during 2009.

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

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	$ 5,663,747	$ 45,198	$ 85,143	$ 1,697,219	$ 3,836,187
Interest on fixed rate long-term debt (a)	4,097,199	307,942	637,125	604,169	2,547,963
Payments on derivatives	94,979	94,979			
Purchase commitments (b)	259,483	256,901	2,582		
Operating lease obligations	314,648	21,041	38,498	30,999	224,110
Totals	$ 10,430,056	$ 726,061	$ 763,348	$ 2,332,387	$ 6,608,260

(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 $912.0 million would be $25.7 million on an annual basis. See Note 5 Debt Obligations to the consolidated financial statements in Item 8 of this report for further discussion of the long-term debt classifications and the maturity dates and interest rates related to long-term debt.

(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

Table of Contents

Index to Financial Statements

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

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

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

Table of Contents

Index to Financial Statements

On January 26, 2009, we 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. We paid this distribution on February 13, 2009 to Unitholders of record at the close of business on February 6, 2009.

The total amount of distributions (all from Available Cash from our 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 -				
Common Units	$ 556,295	$ 113,080	$ 366,180	$ 248,237
Class C Units (1)				3,599
Class E Units (2)	12,484	3,121	12,484	12,484
Class F Units (3)				3,232
Class G Units (4)			40,598	
General Partner -				
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

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(1) Special SCANA distribution see discussion above.
(2) See Note 6 of our consolidated financial statements for more information on the Class E Units.
(3) Class F Units represented limited partnership interests in the Partnership issued to ETE in a private placement in February 2006, subsequently converted to Common Units in August 2006. Prior to conversion of the Class F Units, the Class F Units shared in Partnership distributions and were entitled to all items of Partnership income, gain, loss, deduction and credit as if the Class F Units were Subordinated Units. For more information on the Class F Units, see Note 6 of our consolidated financial statements.
(4) Class G Units which were issued to ETE in November 2006, subsequently converted to Common Units in May 2007. For more information on the Class G Units, see Note 6 of our consolidated financial statements.

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.

Table of Contents

Index to Financial Statements

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 11, 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.

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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 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 10 to our consolidated financial statements included in Item 8 in this report.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this prospectus, words such as anticipate, project, expect, plan, goal, fore intend, could, believe, may, and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our general partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

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

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

the level of domestic oil, propane and natural gas production;

the availability of imported oil and natural gas;

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

Table of Contents

Index to Financial Statements

- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and propane;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs or to the transporting, storing and distributing of propane that may not be fully covered by insurance;
- the maturity of the propane industry and competition from other propane distributors;
- competition from other midstream companies, interstate pipeline companies and propane distribution companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third party pipelines that connect with our pipelines and facilities;

- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;

- the nonpayment or nonperformance by our customers;

- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;

- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, 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 our 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 our financial results and to successfully integrate acquired businesses;

- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and

- the costs and effects of legal and administrative proceedings.

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

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 thouands)
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

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.

Table of Contents

Index to Financial Statements

	Notional Volume (MMBtu)	Fair Value Asset (Liability)	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.

Interest Rate Risk

We are exposed to market risk for increases in interest rates, primarily as a result of our variable rate debt and, in particular, our bank credit facilities. To the extent interest rates increase, our interest expense for our revolving credit facilities will also increase. At December 31, 2008, we had $912.0 million of variable rate debt outstanding and a pay fixed receive float interest rate swap with a notional amount of $125.0 million that is not designated as a hedge. Changes in fair value of the swap are recorded in other income on the consolidated statement of operations. 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 a net effect of $35.1 million in interest expense and other income, in the aggregate, on an annual basis.

We are also subject to interest rate risk on our fixed rate debt if interest rates decrease. To manage this risk, we may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt. For further information, see Note 11 to our consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

Table of Contents

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries as of 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 Partners, 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 Partners, 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

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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	$ 91,902	$ 56,467
Marketable securities	5,915	3,002
Accounts receivable, net of allowance for doubtful accounts	591,257	822,027
Accounts receivable from related companies	17,895	24,438
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 current assets	75,215	54,274
Total current assets	1,183,401	1,409,959
PROPERTY, PLANT AND EQUIPMENT, net	8,296,085	6,433,788
ADVANCES TO AND INVESTMENT IN AFFILIATES	10,110	86,167
GOODWILL	743,694	728,109
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	394,199	350,138
Total assets	$ 10,627,489	$ 9,008,161

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

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands, except unit data)

	December 31, 2008	December 31, 2007
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 381,135	$ 672,388
Accounts payable to related companies	34,547	48,483
Exchanges payable	54,636	40,382
Customer advances and deposits	106,679	75,831
Accrued wages and benefits	64,692	35,408
Accrued capital expenditures	153,230	87,622
Accrued and other current liabilities	94,066	133,258
Price risk management liabilities	94,978	4,358
Interest payable	106,259	63,254
Income taxes payable	14,538	7,012
Deferred income taxes	589	429
Current maturities of long-term debt	45,198	47,036
Total current liabilities	1,150,547	1,215,461
LONG-TERM DEBT, less current maturities	5,618,549	4,297,264
DEFERRED INCOME TAXES	100,597	102,762
MINORITY INTERESTS AND OTHER NON-CURRENT LIABILITIES	14,727	13,483
COMMITMENTS AND CONTINGENCIES (Note 9)		
	6,884,420	5,628,970
PARTNERS CAPITAL:		
General Partner	161,159	160,193
Limited Partners:		
Common Unitholders (152,102,471 and 142,069,957 units authorized, issued and outstanding at December 31, 2008 and 2007, respectively)	3,578,997	3,192,092
Class E Unitholders (8,853,832 units authorized, issued and outstanding - held by subsidiary and reported as treasury units)		
Accumulated other comprehensive income	2,913	26,906
Total partners capital	3,743,069	3,379,191
Total liabilities and partners capital	$ 10,627,489	$ 9,008,161

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

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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	126,113	45,824	227,072	182,226
Total revenues	9,293,868	2,349,510	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	262,151	71,333	179,162	117,415
Selling, general and administrative	194,227	59,132	145,417	107,505
Total costs and expenses	8,176,289	2,025,876	5,962,385	7,216,225
OPERATING INCOME	1,117,579	323,634	829,652	642,871
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(265,701)	(66,298)	(175,563)	(113,857)
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	(50,989)	(1,013)	31,032	
Allowance for equity funds used during construction	63,976	7,276	4,948	
Other, net	9,306	(5,202)	2,019	14,620
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	872,703	272,613	690,939	544,006
Income tax expense	6,680	10,789	13,658	25,920
INCOME BEFORE MINORITY INTERESTS	866,023	261,824	677,281	518,086
Minority interests			(1,142)	(2,234)
NET INCOME	866,023	261,824	676,139	515,852
GENERAL PARTNER S INTEREST IN NET INCOME	315,896	91,011	235,876	118,985
LIMITED PARTNERS INTEREST IN NET INCOME	$ 550,127	$ 170,813	$ 440,263	$ 396,867

BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 3.75	$ 1.22	$ 3.32	$ 3.16
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	146,871,261	137,624,934	132,618,053	109,036,265
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 3.74	$ 1.21	$ 3.31	$ 3.15
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	147,090,608	138,013,366	132,877,152	109,334,778

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

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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	2006
Net income	$ 866,023	$ 261,824	$ 676,139	$ 515,852
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(34,901)	(17,269)	(160,420)	(74,507)
Change in value of derivative instruments accounted for as cash flow hedges	17,326	21,626	175,720	167,525
Change in value of available-for-sale securities	(6,418)	(98)	280	(634)
	(23,993)	4,259	15,580	92,384
Comprehensive income	$ 842,030	$ 266,083	$ 691,719	$ 608,236

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

98

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(Dollars in thousands)

		Limited Partners					
	General Partner	Common Unitholders	Class C Unitholders	Class F Unitholders	Class G Unitholders	Accumulated Other Comprehensive Income (Loss)	Total
Balance, August 31, 2005	$ 49,384	$ 1,362,125	$	$	$	$ (85,317)	$ 1,326,192
Distributions to partners	(88,703)	(248,237)	(3,599)	(3,232)			(343,771)
Issuance of Common and Class F Units to Energy Transfer Equity, LP		38,907		93,476			132,383
Issuance of Common Units in connection with certain acquisitions		4,000					4,000
Conversion to Common Units		93,268		(93,268)			
Capital contribution from General Partner	2,784						2,784
Non-cash unit-based compensation expense		7,038					7,038
Other comprehensive income, net of tax						92,384	92,384
Net income	118,985	390,244	3,599	3,024			515,852
Balance, August 31, 2006	82,450	1,647,345				7,067	1,736,862
Distributions to partners	(215,770)	(366,180)			(40,598)		(622,548)
Issuance of Class G Units to Energy Transfer Equity, LP					1,200,000		1,200,000
Conversion to Common Units		1,208,394			(1,208,394)		
Capital contribution from General Partner	24,490						24,490
Tax effect of remedial income allocation from tax amortization of goodwill		(1,161)					(1,161)
Non-cash unit-based compensation expense		10,471					10,471
Other comprehensive income, net of tax						15,580	15,580
Net income	235,876	391,271			48,992		676,139
Balance, August 31, 2007	127,046	2,890,140				22,647	3,039,833
Distributions to partners	(62,897)	(113,080)					(175,977)
Issuance of units in acquisitions		1,400					1,400
Issuance of units in public offering		234,887					234,887
Capital contribution from General Partner	5,009						5,009
Tax effect of remedial income allocation from tax amortization of goodwill		(1,161)					(1,161)
Units returned by employees for tax withholdings		(164)					(164)

Non-cash executive compensation	24	1,143					1,167
Non-cash unit-based compensation expense		8,114					8,114
Other comprehensive income, net of tax						4,259	4,259
Net income	91,011	170,813					261,824
Balance, December 31, 2007	160,193	3,192,092				26,906	3,379,191
Distributions to partners	(322,923)	(556,295)					(879,218)
Issuance of units in acquisitions		2,228					2,228
Issuance of units in public offering		373,059					373,059
Capital contribution from General Partner	7,968						7,968
Tax effect of remedial income allocation from tax amortization of goodwill		(3,407)					(3,407)
Units returned by employees for tax withholdings		(3,513)					(3,513)
Non-cash executive compensation	25	1,225					1,250
Non-cash unit-based compensation expense		23,481					23,481
Other comprehensive income loss, net of tax						(23,993)	(23,993)
Net income	315,896	550,127					866,023
Balance, December 31, 2008	$ 161,159	$ 3,578,997	$	$	$	$ 2,913	$ 3,743,069

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

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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	Years Ended August 31, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 866,023	$ 261,824	$ 676,139	$ 515,852
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	262,151	71,333	179,162	117,415
Amortization in interest expense	5,886	1,435	4,061	2,807
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	23,481	8,114	10,471	7,038
Non-cash executive compensation	1,250	442		
Deferred income taxes	(5,280)	1,003	(4,042)	(3,827)
Distributions in excess of equity in earnings (losses) of affiliates, net	5,621	4,448	(5,161)	479
Other non-cash	3,382	(2,069)	381	1,382
Net change in operating assets and liabilities, net of acquisitions	74,954	(87,062)	241,182	(98,134)
Net cash provided by operating activities	1,258,145	245,702	1,112,732	543,884
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) repayments from affiliates, net	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	6,015,461	1,741,547	4,757,971	2,829,748
Principal payments on debt	(4,699,123)	(1,062,272)	(4,260,494)	(1,917,451)
Net proceeds from issuance of Limited Partner Units	373,059	234,887	1,200,000	132,383
Capital contribution from General Partner	7,968	29	24,490	2,784
Distributions to partners	(879,218)	(175,977)	(622,548)	(343,771)
Debt issuance costs	(25,272)	(211)	(11,397)	(2,044)
Net cash provided by financing activities	792,875	738,003	1,088,022	701,649
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	35,435	(12,238)	42,664	1,127
CASH AND CASH EQUIVALENTS, beginning of period	56,467	68,705	26,041	24,914

CASH AND CASH EQUIVALENTS, end of period	$	91,902	$	56,467	$	68,705	$	26,041

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

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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 Partners, L.P. and subsidiaries (the Partnership or ETP) 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. 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 our operating 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 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. 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.

Business Operations

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

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

Table of Contents

Index to Financial Statements

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 , ETP , Energy Transfer or the Partnership.

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

Our interstate transportation operations principally focus on natural gas transportation of Transwestern, which owns and operates approximately 2,700 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.

Table of Contents

Index to Financial Statements

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 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 11, 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

Table of Contents

Index to Financial Statements

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 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.

Table of Contents

Index to Financial Statements

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	6,849	(12,557)	(6,003)	3,717
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	(21,077)	(7,944)	11,281	(27,574)
Regulatory assets	(24,588)	(1,918)	663	
Intangibles and other long-term assets	(16,214)	2,523	(2,530)	(2,737)
Accounts payable	(296,185)	195,644	(92,172)	(295,332)
Accounts payable to related companies	(13,957)	29,012	18,564	(467)
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	25,620	(17,139)	12,873	16,514
Accrued and other current liabilities	(30,520)	24,114	(14,912)	53,383
Interest payable	42,952	33,408	14,844	4,476
Income taxes payable	7,526	777	2,543	(2,103)
Other long-term liabilities	1,741	(680)	1,460	(13,179)
Price risk management liabilities, net	75,874	7,022	30,103	119,496
Net change in assets and liabilities, net of effect of acquisitions	$ 74,954	$ (87,062)	$ 241,182	$ (98,134)

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
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	$ 237,620	$ 51,465	$ 184,993	$ 121,329

Cash paid for income taxes	$ 4,674	$ 9,009	$ 8,583	$ 38,131

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.

Table of Contents

Index to Financial Statements

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 December 31, 2008 or 2007; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage segments was not deemed necessary.

Our 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.

Our 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

106

Table of Contents

Index to Financial Statements

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 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.

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.

Table of Contents

Index to Financial Statements

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 our 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.

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

	December 31, 2008	December 31, 2007
Land and improvements	$ 74,731	$ 65,184
Buildings and improvements (10 to 30 years)	129,714	114,201
Pipelines and equipment (10 to 80 years)	5,136,357	3,657,326
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)	358,669	263,876
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
	7,287,894	5,552,618
Less Accumulated depreciation	(700,826)	(465,202)
	6,587,068	5,087,416
Plus Construction work-in-process	1,709,017	1,346,372
Property, plant and equipment, net	$ 8,296,085	$ 6,433,788

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	Years Ended August 31, 2006
Depreciation expense	$ 244,689	$ 64,569	$ 163,630	$ 107,148
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.

Table of Contents

Index to Financial Statements

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.

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 $743.7 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 month 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	Total
Balance, August 31, 2007	$ 13,409	$ 10,327	$ 107,550	$ 587,143	$ 718,429
Purchase accounting adjustments			(8,937)	190	(8,747)
Goodwill acquired	10,959			7,742	18,701
Sale of operations				(274)	(274)
Balance, December 31, 2007	24,368	10,327	98,613	594,801	728,109
Purchase accounting adjustments				2,457	2,457
Goodwill acquired	9,141			15,346	24,487
Goodwill impairment	(11,359)				(11,359)
Balance December 31, 2008	$ 22,150	$ 10,327	$ 98,613	$ 612,604	$ 743,694

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).

Table of Contents

Index to Financial Statements

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)	59,108	(16,586)	42,432	(10,578)
Regulatory assets	98,560	(5,941)	73,687	(2,623)
Other	43,153		26,808	
Total intangibles and other long-term assets	$ 486,818	$ (92,619)	$ 412,910	$ (62,772)

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	$ 6,008	$ 1,710	$ 4,502	$ 2,550

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

Years Ending December 31:	
2009	$ 26,891
2010	25,013
2011	23,348
2012	19,802
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.

Table of Contents

Index to Financial Statements

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	31,753	29,341
Total accrued and other current liabilities	$ 94,066	$ 133,258

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 $5.10 billion and $5.66 billion, respectively. At December 31, 2007, the aggregate fair value and carrying amount of long-term debt was $4.33 billion and $4.34 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. 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.

Table of Contents

Index to Financial Statements

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 Reporting 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	(51,642)		(51,642)
	$ 22,450	$ 112,005	$ (89,555)

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
Totals	$ 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 year 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

Table of Contents

Index to Financial Statements

maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs, and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis.

Income Taxes

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

Our partnership will be considered to have terminated for federal income tax purposes if transfers of units within a 12-month period constitute the sale or exchange of 50% or more of our capital and 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. This termination did not affect our classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of our qualifying income for federal income tax purposes. This termination required us to close our taxable year, make new elections as to various tax matters and reset the depreciation schedule for our depreciable assets for federal income tax purposes. The resetting of our depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to our Unitholders. However, certain elections we made in connection with this tax termination allowed us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of our Unitholders, which deductions had not previously been utilized in computing taxable income allocable to our Unitholders.

As a result of the tax termination discussed above, we elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our subsidiary, Heritage Holdings, Inc. (HHI), which owns our Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of our Common Units. The amount of such goodwill accumulated as of the date of our acquisition of HHI (approximately $158.0 million) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. We account for HHI using the treasury stock method due to its ownership of our Class E units. Due to the accounting principles outlined in Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109) and related Interpretations, we account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of our HHI purchase price allocation, which effectively results in a charge to our common equity and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the year ended 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

Table of Contents

Index to Financial Statements

(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.

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. See Note 11 for additional information related to interest rate derivatives.

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

Table of Contents

Index to Financial Statements

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 distributions based on the most recently declared distributions as of the grant date.

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.

Table of Contents

Index to 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.

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. Accordingly, we are required to record and disclose EPS information following existing GAAP until January 1, 2009. While the actual impact of EITF 07-4 will depend on each specific period s earnings and distributions, the principles established in EITF 07-4 differ significantly from the present method used to compute earnings per unit when earnings exceed distributions. Depending on the actual earnings achieved, the impact of EITF 07-4 on the computation of our earnings per limited partner unit may be significant. Had we applied EITF 07-4 basic and diluted earning per limited partner unit for the periods presented would have been:

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	2006
Weighted average limited partner units basic	146,871,261	137,624,934	132,618,053	109,036,265
Basic net income per limited partner unit	$ 3.75	$ 1.24	$ 3.32	$ 3.61
Weighted average limited partner units	146,871,261	137,624,934	132,618,053	109,036,265
Dilutive effect of Unit Grants	219,347	388,432	259,099	298,513

Weighted average limited partner units, assuming dilutive effect of Unit Grants	147,090,608	138,013,366	132,877,152	109,334,778
Diluted net income per limited partner unit	$ 3.74	$ 1.24	$ 3.31	$ 3.60

116

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

Table of Contents

Index to Financial Statements

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, we 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, we 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.

Table of Contents

Index to Financial Statements

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, pursuant to agreements entered into with GE Energy Financial Services (GE) and Southern Union Company (Southern Union), we acquired the member interests in CCE Holdings, LLC (CCEH) from GE and certain other investors for $1.00 billion. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to Energy Transfer Equity, L.P. simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP s 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and separate segment of ETP.

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

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

In September 2006, we acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of $30.6 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 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, we 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

Table of Contents

Index to Financial Statements

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

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.

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.

Table of Contents

Index to Financial Statements

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
Other	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 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.

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.

Table of Contents

Index to Financial Statements

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 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 to 15 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	$ 359,724

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

Table of Contents

Index to Financial Statements

Pro Forma Results of Operations (Unaudited)

The following unaudited pro forma consolidated results of operations for the year ended August 31, 2007 are presented as if the Transwestern acquisition had been 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 had been consummated on September 1, 2005.

	Years Ended August 31,	
	2007	2006
Revenues	$ 6,850,929	$ 8,421,824
Net income	$ 693,045	$ 587,873
Limited Partners interest in net income	$ 456,831	$ 441,815
Basic earnings per Limited Partner Unit	$ 3.31	$ 2.93
Diluted earnings per Limited Partner Unit	$ 3.30	$ 2.93

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:

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

Table of Contents

Index to Financial Statements

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

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Net income	$ 866,023	$ 261,824	$ 676,139	$ 515,852
Adjustments:				
General Partner s equity ownership	(17,321)	(5,236)	(13,523)	(10,172)
General Partner s incentive distributions	(298,575)	(85,775)	(222,353)	(108,813)
Limited Partner s interest in net income	550,127	170,813	440,263	396,867
Additional earnings allocation to General Partner		(3,430)		(48,781)
Less earnings allocated to Class C Units as a result of the SCANA settlement (a)				(3,599)
Net income available to limited partners	$ 550,127	$ 167,383	$ 440,263	$ 344,487
Weighted average limited partner units basic	146,871,261	137,624,934	132,618,053	109,036,265
Basic net income per limited partner unit	$ 3.75	$ 1.22	$ 3.32	$ 3.16
Weighted average limited partner units	146,871,261	137,624,934	132,618,053	109,036,265
Dilutive effect of Unit Grants	219,347	388,432	259,099	298,513
Weighted average limited partner units, assuming dilutive effect of Unit Grants	147,090,608	138,013,366	132,877,152	109,334,778
Diluted net income per limited partner unit	$ 3.74	$ 1.21	$ 3.31	$ 3.15

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(a) As a result of the SCANA settlement discussed in Note 6, we collected a settlement of $7.7 million, net of $3.3 million of attorney fees, during the year ended August 31, 2006. We retained $0.5 million for litigation expenses previously incurred. The remaining $7.2 million was allocated $3.6 million to the Common and Class F Limited Partner Units and $3.6 million as a special one-time distribution to the holder of our Class C Units for that amount normally allocated to our General Partner. The Limited Partners share of available net income has been reduced accordingly.

5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

ETP Senior Notes:	December 31, 2008	December 31, 2007	Maturities
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.

Table of Contents

Index to Financial Statements

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.
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:			
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	2,565	3,174	Due in installments through 2024.
	5,663,747	4,344,300	
Current maturities	(45,198)	(47,036)	
	$ 5,618,549	$ 4,297,264	

Table of Contents

Index to Financial Statements

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

2009	$ 45,198
2010	40,729
2011	44,414
2012	1,324,853
2013	372,366
Thereafter	3,836,187
	$ 5,663,747

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 the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership s subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

ETP 9.70% Senior Notes

In December 2008, we 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, we 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). We 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 our $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.

Table of Contents

Index to Financial Statements

The ETP 364-Day Credit Facility was a single draw term loan used for general corporate purposes, under which we 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 any of our 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.

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

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

Table of Contents

Index to Financial Statements

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.

Covenants Related to Our Credit Agreements

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. The agreements and indentures related to 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);

Table of Contents

Index to Financial Statements

- 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 we make 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.

6. PARTNERS CAPITAL

Registration Statement

During fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1.50 billion aggregate offering price of Common Units representing our Limited Partner interests. Through December 31, 2008, we have not made any sales under this Registration Statement.

In December 2007, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register an unspecified quantity of Common Units and an unspecified dollar amount of debt securities, in each case that may be offered for sale by us from time to time.

Limited Partner Units

Limited Partner interests are represented by Common and Class E Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of December 31, 2008, there were issued and outstanding 152,102,471 Common Units representing an aggregate 98% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

Table of Contents

Index to Financial Statements

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance. In addition to this right, ETP GP, as our General Partner, has an obligation to contribute additional capital in connection with any such issuance of equity securities by us in order to maintain its 2% general partner interest as discussed below.

Incentive Distribution Rights represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read Quarterly Distributions of Available Cash below. ETP GP owns all of the Incentive Distribution Rights.

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	142,069,957	136,981,221	110,726,999	106,889,904
Issuance of Common Units in connection with certain acquisitions	53,893	27,348		99,955
Common Units issued in connection with public offerings	9,662,500	5,000,000		
Issuance of restricted Common Units			167,265	97,140
Issuance of Common Units to Energy Transfer Equity, LP				1,069,850
Conversion of Class F Units to Common Units				2,570,150
Conversion of Class G Units to Common Units			26,086,957	
Issuance of Common Units under the equity incentive plans	406,677	64,600		
Units relinquished by employees for tax withholdings	(90,556)	(3,212)		
Number of Units, end of period	152,102,471	142,069,957	136,981,221	110,726,999

Our Common Units are registered under the Securities Act of 1934 and are listed for trading on the New York Stock Exchange. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under Quarterly Distributions of Available Cash.

2008 and Subsequent Activity

During 2008 we issued a total of 9,662,500 Common Units in connection with public offerings as follows:

On January 8, 2008, we issued 750,000 Common Units at $48.81 per 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 our December 2007 public offering of 5,000,000 ETP Common Units (see below). The proceeds of $35.0 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility.

On July 21, 2008, we issued 8,912,500 Common Units at $39.45 per Common Unit in connection with a public offering. Net proceeds of approximately $338.0 million from the offering were used to repay a portion of the amount outstanding under the ETP Credit Facility.

Table of Contents

Index to Financial Statements

On January 27, 2009, we closed a public offering of 6,900,000 Common Units at $34.05 per Common Unit. Net proceeds from the offering were used by us to repay approximately $225.9 million of outstanding debt under our revolving ETP Credit Facility. We expect to use some of the increased availability under the revolving credit facility to finance capital expenditures and other growth projects.

Also during the fiscal 2008 period:

we issued at total of 406,677 Common Units under our equity incentive plans (discussed below) of which 2,752 were Director Awards, which vested on September 1, 2008. An additional 1,366 units were awarded to certain directors on December 28, 2008.

During the fourth quarter of fiscal year 2008, certain of the participants in the 2004 Unit Plan elected to have a portion of the ETP Common Units to which they were entitled to upon vesting of restricted units granted to them pursuant to the 2004 Unit Plan withheld by the Partnership to satisfy the Partnership s tax withholding obligations. None of the ETP Common Units were purchased by the Partnership through a publicly announced plan or program.

In October 2008 employees relinquished a total of 69,000 Common Units under the 2004 Unit Plan provision. The fair market value of the units was determined by the Compensation Committee as an average of $35.28 per unit, determined as the arithmetic average of the closing price for the 10 trading days prior to respective vesting dates based on the date the employees were first notified of the ability to relinquish the units for such tax payment.

In December 2008 employees relinquished a total of 21,556 Common Units under the 2004 Unit Plan provision. The fair market value of the units was determined by the Compensation Committee as $30.71 per unit, determined as the arithmetic average of the closing price for the 10 trading days prior to December 5, 2008, the date the employees were first notified of the ability to relinquish the units for such tax payment.

Four-Month Transition Period Ended December 31, 2007 Activity

On December 18, 2007, the Partnership sold in a public offering 5,000,000 Common Units representing limited partner interests at $48.81 per common unit. ETP used the offering proceeds of approximately $235.0 million, net of issuance costs, to repay a portion of the outstanding debt under the ETP Term Loan Facility. The remaining balance on the ETP Term Loan Facility was repaid with funds from the ETP Credit Facility. ETP also granted the underwriters a 30-day option to purchase up to an aggregate of 750,000 additional Common Units to cover over-allotments, if any. The underwriters exercised their option in full on January 8, 2008 (see above).

Also during the four-month transition period 2007:

we issued at total of 64,600 Common Units under our 2004 Unit Plan (discussed below) of which 56,482 were employee awards and 8,118 were Director Awards, which vested on September 1, 2007.

employees relinquished a total of 3,212 Common Units under the 2004 Unit Plan provision which provides that recipients may elect to relinquish their right to a portion of the vested units as payment for the income tax obligations arising as a result of the unit vesting, based on the Compensation Committee s determination of the fair market value of the units. For the four-month period ended December 31, 2007, participants entitled to unit vesting elected to relinquish a total of 3,212 units under such provision. The fair market value of the units was determined by the Compensation Committee as $51.15 per unit, determined as the arithmetic average of the closing price for the 10 trading days prior to October 2, 2007, the date the employees were first notified of the ability to relinquish the units for such tax payment.

Fiscal Year 2007 Activity

On November 1, 2006, we issued 26,086,957 Class G Units to ETE for aggregate proceeds of $1.20 billion in order to fund a portion of the Transwestern Acquisition and to repay indebtedness we incurred in connection with the Titan acquisition. The Class G Units, a newly created class of our limited partner interests, were issued to ETE at a price of $46.00 per unit, based upon a market discount from the closing price of our Common Units on October 31, 2006 of $48.94. The terms of the Class G Units are described in more detail below. The Class G Units were issued to ETE pursuant to a customary agreement, and registration rights were granted to ETE.

Table of Contents

Index to Financial Statements

Also during fiscal year 2007, we:

- issued a total of 167,265 Common Units under our Restricted Unit Plan (as discussed in Unit Based Compensation Plans below) of which 156,573 were employee awards under our 2004 Unit Plan (discussed below), 7,025 were Director Awards under our 2004 Unit Plan, and 3,667 were Director Awards under our Restricted Unit Plan which vested on September 1, 2006. As of August 31, 2007, there were no unvested awards remaining under the Restricted Unit Plan (terminated in June 2004). No additional grants have been, or will be, made under the Restricted Unit Plan; and,

- converted 26,086,957 Class G Units to Common Units (see details in *Class G Units* below).

Fiscal Year 2006 Activity

On February 6, 2006, pursuant to its General Partner authority, our General Partner amended our Amended and Restated Agreement of Limited Partnership to create a new class of limited partner interests titled Class F Units (the terms of the Class F Units are described in more detail below). On February 8, 2006, we sold and issued 1,069,850 Common Units (and 2,570,150 Class F Units) representing limited partner interests in the Partnership, to ETE in a private placement. ETE owns 100% of the 2% General Partner interests in ETP GP and 100% of the Incentive Distribution Rights in the Partnership (which it holds through its ownership interests in ETP GP). The price paid for each of the Common Units and Class F Units was equal to $36.37 per unit, the New York Stock Exchange closing price of the Partnership s Common Units on February 8, 2006. Of the aggregate proceeds of $132.4 million from the sale, $75.0 million was used to extinguish the HOLP Senior Revolving Acquisition Facility, to pay down the HOLP Senior Revolving Working Capital Facility, and for HOLP general operating purposes. The remaining proceeds of $57.4 million were used to pay down existing debt on the ETP Credit Facility and for general Partnership operating purposes.

Also during fiscal year 2006, we:

- issued 99,955 Common Units valued at $4.0 million in connection with a propane acquisition to the former owners of such operations;

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

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

Class C Units

In August 2000, 1,000,000 Class C Units were issued to HHI in conjunction with the U.S. Propane transaction and the change of control of our General Partner in conversion of that portion of HHI s Incentive Distribution Rights that entitled it to receive any distribution attributable to the net amount we received in connection with the settlement, judgment, award or other final nonappealable resolution of specified litigation we filed prior to the transaction with U.S. Propane, referred to as the SCANA litigation. The Class C Units had a zero initial capital account balance and were distributed by HHI to its former stockholders in connection with the U.S. Propane transaction. On June 1, 2006, we received net settlement proceeds of $7.7 million on all four of our claims with respect to the SCANA litigation (see Note 10).

All decisions of our General Partner relating to the SCANA litigation were determined by a special litigation committee consisting of one or more independent directors of our General Partner. On June 20, 2006, the special litigation committee approved the distribution of all litigation proceeds we received after deducting all costs and expenses we and our affiliates incurred in connection with the SCANA litigation and any cash reserves necessary or appropriate to provide for operating expenditures. Following this determination, the distributable proceeds were deemed to be Available Cash under the Partnership Agreement and were distributed on July 14, 2006 (as described below under Quarterly Distributions of Available Cash). Such distribution totaled $3.5 million, $3.6 million and $0.8 million to the Common Units, Class C Units and Class F Units ($0.0325 per Common and Class F Unit), respectively.

Table of Contents

Index to Financial Statements

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

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

Class E Units

There are 8,853,832 Class E Units outstanding that are reported as treasury units. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. Management plans to leave the Class E Units in the form described here indefinitely. In the event of our termination and liquidation, the Class E Units will be allocated 1% of any gain upon liquidation and will be allocated any loss upon liquidation to the same extent as Common Units. After the allocation of such amounts, the Class E Units will be entitled to the balance in their capital accounts, as adjusted for such termination and liquidation. The terms of the Class E Units were determined in order to provide us with the opportunity to minimize the impact of our ownership of Heritage Holdings, including the $57.4 million in deferred tax liabilities of Heritage Holdings that were included in the purchase of Heritage Holdings. The Class E Units are treated as treasury stock for accounting purposes because they are owned by our wholly-owned subsidiary, Heritage Holdings. Due to the ownership of the Class E Units by this corporate subsidiary, the payment of distributions on the Class E Units will result in annual tax payments by Heritage Holdings at corporate federal income tax rates, which tax payments will reduce the amount of cash that would otherwise be available for distribution to us as the owner of Heritage Holdings. Because distributions on the Class E Units will be available to us as the owner of Heritage Holdings, those funds will be available, after payment of taxes, for general partnership purposes, including to satisfy working capital requirements, for the repayment of outstanding debt and to make distributions to the Unitholders. Because the Class E Units are not entitled to receive any allocation of Partnership income, gain, loss, deduction or credit that is attributable to our ownership of Heritage Holdings, such amounts will instead be allocated to the General Partner in accordance with its respective interest and the remainder to all Unitholders other than the holders of Class E Units pro rata. In the event that Partnership distributions exceed $1.41 per unit annually, all such amounts in excess thereof will be available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests.

Class F Units

As discussed above, on February 8, 2006, we issued 2,570,150 Class F Units representing limited partnership interests in the Partnership to ETE in a private placement that is exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended. On August 15, 2006 our Common Unitholders approved a proposal to change the terms of the Class F Units and each Class F Unit converted to Common Units on a one-for-one basis. Prior to conversion of the Class F Units, the Class F Units shared in Partnership distributions and were entitled to all items of Partnership income, gain, loss, deduction and credit as if the Class F Units were Subordinated Units.

Class G Units

As discussed above, on November 1, 2006, we issued 26,086,957 Class G Units to ETE for aggregate proceeds of $1.20 billion. The terms of the Class G Units provided that they may be converted to Common Units on a one-for-one basis upon approval of a majority of the votes cast by the holders of our Common Units provided that the total votes cast by such holders represent a majority of the Common Units entitled to vote. The Class G Units were issued to ETE pursuant to a customary agreement, and registration rights were granted to ETE. On May 1, 2007, at a special meeting of the Common Unitholders, the Unitholders approved the conversion of Class G Units to Common Units and all of the outstanding Class G Units converted to Common Units on a one-for-one basis on such date.

Table of Contents

Index to Financial Statements

Quarterly Distributions of Available Cash

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

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

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

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

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

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

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

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

Table of Contents

Index to Financial Statements

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 our 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 see discussion in Class C Units above and Note 10 for further information.

On January 26, 2009, we 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. We paid this distribution on February 13, 2009 to Unitholders of record at the close of business on February 6, 2009.

The total amounts of distributions declared during the years ended December 31, 2008, August 31, 2007 and 2006 and the four-month transition period ended December 31, 2007 are 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	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 (2)	12,484	3,121	12,484	12,484
Class F Units (3)				3,232
Class G Units (4)			40,598	
General Partner				
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 Note 10.
(2) See explanation of Class E Units above.
(3) Distributions declared prior to the Class F Units converting to Common Units (see detail above).
(4) Distributions declared prior to the Class G Units converting to Common Units (see detail above).

135

Table of Contents

Index to Financial Statements

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.

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income (AOCI), net of tax:

	December 31, 2008	December 31, 2007
Net gain on commodity related hedges	$ 8,735	$ 25,497
Net gain on interest rate hedges	161	926
Unrealized gains (losses) on available-for-sale securities	(5,983)	483
Total AOCI, net of tax	$ 2,913	$ 26,906

7. UNIT-BASED COMPENSATION PLANS:

We have 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 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 our board of directors. Up to 5,000,000 ETP Common Units may be granted as awards under the 2008 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2008 Incentive Plan. The 2008 Incentive Plan is effective until December 16, 2018 or, if earlier, the time which all available units under the 2008 Incentive Plan have been issued to participants or the time of termination of the plan by our board of directors. As of December 31, 2008, a total of 4,776,655 ETP Common Units remain available to be awarded under the 2008 Incentive Plan.

2004 Unit Plan. Our Amended and Restated 2004 Unit Award Plan (the 2004 Unit Plan) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers, and directors. Any awards that are forfeited or which expire for any reason or any units which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. As of December 31, 2008, 16,847 ETP Common Units were available for future grants under the 2004 Unit Plan.

*Restricted Unit Plan***.** The Restricted Unit Plan provided rights for certain directors and key employees of ETP GP and its affiliates to acquire up to 292,000 Common Units of ETP. Following the June 23, 2004 approval of the 2004 Unit Plan at the special meeting of the ETP Unitholders, the Restricted Unit Plan was terminated (except for the obligation to issue Common Units at the time the 16,592 grants previously awarded vest), and no additional grants have been or will be made under the Restricted Unit Plan. 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.

Employee Grants

Prior to December 2007, substantially all of the awards granted to employees under the 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 our units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the Compensation Committee, 65% of such one-third vesting if the total return of our units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of our units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of our units for the year plus the aggregate per unit cash distributions received for the year. Non-cash compensation expense is recorded for these 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 our 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 employee unit awards including unit awards granted to our executive officers.

Commencing in December 2007, we have 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 our 2004 Unit Plan generally require the continued employment of the recipient during the vesting period. The Compensation Committee has in the past and may in the future, but is not required to, accelerate the vesting of unvested unit awards in the event of the termination or retirement of an executive officer. During the year ended December 31, 2008, the Compensation Committee did not accelerate the vesting of any unvested unit awards granted under the 2004 Unit Plan.

In October 2008 and December 2008, the Compensation Committee approved the grant of new unit awards under the 2004 Unit Plan and 2008 Incentive Plan (defined below) to certain of our employees, including certain of our 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 Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our 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, we 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.

Table of Contents

Index to Financial Statements

The following table shows the activity of the 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.

Table of Contents

Index to Financial Statements

We recognized non-cash unit-based compensation expense related to employee grants under our 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

Director Grants

The 2008 Incentive Plan provides for annual grants of ETP Common Units to non-employee directors of our General Partner equal to $50 thousand divided by the fair market value of our Common Units as of each anniversary date of December 19, 2008, the date of the adoption of the 2008 Incentive Plan.

Under the 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 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 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 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 forfeited during fiscal year 2006	(730)	32.98
Unvested awards as of August 31, 2006	15,951	22.54
Initial Director Grants awarded in fiscal year 2007		
Annual Director Grants awarded in fiscal year 2007	3,240	41.47
Awards vested during fiscal year 2007	(7,025)	22.45
Awards forfeited during fiscal year 2007		
Unvested awards as of August 31, 2007	12,166	27.63
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

Table of Contents

Index to Financial Statements

We recognized non-cash compensation expense related to director grants under our 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 Director Awards as of December 31, 2008 was:

Years Ending December 31:	
2009	$ 122
2010	44
2011	10

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

140

Table of Contents

Index to Financial Statements

8. 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	12,216	5,705	9,803	1,994
Total	12,036	8,695	17,699	29,634
Deferred provision:				
Federal	(5,634)	1,482	(4,598)	(3,329)
State	278	612	557	(385)
Total	(5,356)	2,094	(4,041)	(3,714)
Total Tax Provision	$ 6,680	$ 10,789	$ 13,658	$ 25,920

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	1.25%	1.82%	1.25%	3.10%
Earnings not subject to tax at the Partnership level	(35.48)%	(32.86)%	(34.25)%	(33.30)%
Effective tax rate	0.77%	3.96%	2.00%	4.80%

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	$ 105,032	$ 102,637
Other, net	(3,846)	554
Total deferred tax liability	$ 101,186	$ 103,191

9. <u>MAJOR CUSTOMERS AND SUPPLIERS:</u>

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.

Table of Contents

Index to Financial Statements

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 10).

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.

10. 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 the 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.

Table of Contents

Index to Financial Statements

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 2008 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 79.0 million gallons of propane per year that contains a two-year cancellation provision and a seven year contract to purchase not less than 90.0 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

Table of Contents

Index to Financial Statements

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 new 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 13) 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 our investment in M-P Energy in October 2007, we executed a seven-year propane purchase agreement for approximately 90.0 million gallons per year at market prices plus a nominal fee.

We previously had a percentage guaranty with a financial institution whereby we would be liable for our 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 us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the

Table of Contents

Index to Financial Statements

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). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Our 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, we 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, our 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 our operating income for our 2008 year. If the FERC is successful in revoking our blanket marketing authority, our 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 our own production, and any other sales of natural gas by us would be required to be made at contract prices that would be subject to individual FERC approval.

In its Order and Notice, the FERC specified that it was 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 our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. 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 the 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 s 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 judges initial decisions due by May 11, 2009, however, as discussed below, we 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 judge s 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 judges 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 our 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. We 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 our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC holds substantial enforcement authority. At this time, we are unable 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 (CEA) by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, we entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, we agreed to pay the CFTC $10.0 million and the CFTC agreed to release us and our affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that we are 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, we 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 ETE 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 ETE 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 ETE contains an additional allegation that we and ETE transported gas in a manner that favored our 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 producer/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 us in the United States District Court for the Southern District of Texas. This action alleges that we 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, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us 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, we 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, we filed a motion to dismiss the complaint. On June 19, 2008, the plaintiffs filed a response opposing our motion to dismiss. We filed a reply in support of our motion on July 9, 2008.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we 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 we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our 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, we filed a motion to dismiss this complaint. On July 2, 2008 the plaintiffs filed a response opposing our motion to dismiss. We 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.

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.

Table of Contents

Index to Financial Statements

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 HOLP, it is believed that HOLP s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

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 December 31, 2008 or our December 31, 2007 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of

Table of Contents

Index to Financial Statements

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.

11. 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.

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.

Table of Contents

Index to Financial Statements

The following table details the outstanding commodity-related derivatives:

December 31, 2008

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
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

Table of Contents

Index to Financial Statements

$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% Receive Float	No	$ 1,134	$ 1,530
December 2009	500,000	Pay Fixed 3.99% Receive Float	No	50,509	

We reclassified into earnings gains of $0.6 million, losses of $0.9 million, and gains of $1.4 million for the year ended December 31, 2008 and the years ended August 31, 2007 and 2006, respectively, related to interest rate swaps that were previously reported in AOCI. For the four months ended December 31, 2007, an insignificant amount of losses was reclassified into earnings. We expect gains of $0.3 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, could differ as interest rates change.

The following table represents pre-tax balances in AOCI related to interest rate swaps accounted for as cash flow hedges:

				Accumulated Other Comprehensive Income (Loss) as of	
Date Settled	Term	Notional Amount	Type	December 31, 2008	December 31, 2007
April 2007	2014	$ 400,000	LIBOR	$ (10,622)	$ (11,135)
June 2006	2016	200,000	Forward Starting Treasury Lock	11,017	12,210
January 2005	2017	100,000	Treasury Lock	(234)	(269)
				$ 161	$ 806

153

Table of Contents

Index to Financial Statements

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	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 gains (losses) on non-hedged interest rate swaps included in other income	$ (50,113)	$ (1,032)	$ (1,646)	$ 276
Ineffective portion of cash flow derivatives included in interest expense			(1,813)	842
Realized gains on interest rate swaps included in interest expense and other income	(230)	38	33,291	643

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.

12. RETIREMENT BENEFITS:

We sponsor a defined contribution profit sharing and 401(k) savings plan, which covers virtually all employees subject to service period requirements. Profit sharing contributions are made to the plan at the discretion of the Board of Directors and are allocated to eligible employees as of the last day of the plan year. Employer matching contributions are calculated using a discretionary formula based on employee contributions. We made matching contributions of $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.

13. RELATED PARTY TRANSACTIONS:

On May 7, 2007, Ray Davis, previously the Co-Chairman of ETE and Co-Chairman and Co-Chief Executive Officer of ETP (retired August 15, 2007), and Natural Gas Partners VI, L.P. (NGP) and affiliates of each, sold approximately 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise GP Holdings, L.P. (Enterprise or EPE). In addition to the purchase of ETE Common Units, Enterprise also acquired a 34.9% non-controlling equity interest in ETE s General Partner, LE GP, L.L.C. (LE GP). As a result of these transactions, EPE and its subsidiaries are considered related parties.

Table of Contents

Index to Financial Statements

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:

Table of Contents

Index to Financial Statements

	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
ETP GP	$ 122	$ 5,113
ETE	2,632	1,553
MEP	2,805	743
McReynolds Energy	202	
Energy Transfer Technologies, Ltd.	16	922
Others	449	2,941
Total accounts receivable from related companies excluding Enterprise	$ 6,226	$ 11,272

As of December 31, 2007, we had advances due from a propane joint venture of $18.2 million, which was 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.

During fiscal year 2006 we entered into a shared services agreement effective upon the initial public offering of ETE. Under the terms of the shared services agreement, ETE pays us an annual administrative fee of approximately $0.5 million for the provision of various general and administrative services. Fees recognized since the inception of this agreement 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 approximately $0.7 million from an entity that includes one of the General Partner s directors.

The Chief Executive Officer (CEO) of our 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.

Table of Contents

Index to Financial Statements

14. SUMMARIZED CONDENSED CONSOLIDATING FINANCIAL STATEMENTS:

Prior to July 20, 2007, when the Partnership entered into an Amended and Restated Credit Agreement (see Note 5), our Revolving Credit Facility and Senior Notes were fully and unconditionally guaranteed by ETC OLP and Titan (beginning in fiscal year 2006) and all of their direct and indirect wholly-owned subsidiaries (the Subsidiary Guarantors). In connection with the Partnership entering into the Amended and Restated Credit Agreement (described in more detail in Note 5), all guarantees by ETC OLP and all of its direct and indirect wholly-owned subsidiaries for the Partnership s 5.65% Senior Notes due 2012 and 5.95% Senior Notes due 2015 (the 2005 Senior Notes), and the Partnership s 6.125% Senior Notes due 2017 and 6.625% Senior Notes due 2036 (the 2006 Senior Notes), were released and discharged. HOLP and its direct and indirect subsidiaries and HHI do not guarantee the ETP Credit Facility and Senior Notes. Following is our consolidating financial information including our midstream and propane Subsidiary Guarantors, our Non-Guarantor Subsidiaries and the Partnership for the fiscal year ended August 31, 2006 (the period during which the Partnership debt was guaranteed as noted above). The condensed consolidating financial information presented herein complies with Rule 3-10 of Regulation S-X, is prepared on the equity method, and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America.

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended August 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 6,877,512	$	$	$	$ 6,877,512
Propane			47,063	752,295		799,358
Other			5,908	176,318		182,226
Total revenue		6,877,512	52,971	928,613		7,859,096
COSTS AND EXPENSES:						
Cost of products sold - midstream and transportation and storage		5,963,422				5,963,422
Cost of products sold - propane			30,751	462,891		493,642
Cost of products sold - other			1,252	110,000		111,252
Operating expenses		203,221	21,433	198,335		422,989
Depreciation and amortization		58,222	3,812	55,381		117,415
Selling, general and administrative	17,256	70,442	2,950	16,857		107,505
Total costs and expenses	17,256	6,295,307	60,198	843,464		7,216,225
OPERATING INCOME (LOSS)	(17,256)	582,205	(7,227)	85,149		642,871
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(96,342)	47	(301)	(29,166)	11,905	(113,857)
Equity in earnings (losses) of affiliates	618,225	(514)		35	(618,225)	(479)
Gain on disposal of assets		679		172		851
Interest and other income (expense), net	11,226	7,631	(7)	7,675	(11,905)	14,620
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	515,853	590,048	(7,535)	63,865	(618,225)	544,006
Income tax expense (benefit)	(1)	(18,345)	9	(7,583)		(25,920)
INCOME BEFORE MINORITY INTERESTS	515,852	571,703	(7,526)	56,282	(618,225)	518,086
Minority interests		(1,349)		(885)		(2,234)
NET INCOME	$ 515,852	$ 570,354	$ (7,526)	$ 55,397	$ (618,225)	$ 515,852

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended August 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (92,454)	$ 523,548	$ 3,380	$ 109,410	$	$ 543,884
CASH FLOWS FROM INVESTING ACTIVITIES:						
Cash paid for acquisitions, net of cash acquired	(572,947)	(17,124)	(1,153)	(19,419)	24,458	(586,185)
Working capital settlement on prior year acquisitions		19,653				19,653
Capital expenditures		(632,835)	(3,053)	(44,276)		(680,164)
Advances to and investment in affiliates	(157,387)			(4,651)	157,387	(4,651)
Proceeds from the sale of assets		3,025	812	3,104		6,941
Net cash used in investing activities	(730,334)	(627,281)	(3,394)	(65,242)	181,845	(1,244,406)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from borrowings	2,530,737	19,716	486	278,809		2,829,748
Principal payments on debt	(1,550,456)		(305)	(366,690)		(1,917,451)
Proceeds from borrowings from affiliates	1,598,527	1,859,631	4,850		(3,463,008)	
Payments on borrowings from affiliates	(1,864,481)	(1,571,234)	(27,293)		3,463,008	
Net proceeds from issuance of Common Units	132,383					132,383
Capital contribution from General Partner	2,784	57,387		100,000	(157,387)	2,784
Distributions to parent		(261,805)		(64,657)	326,462	
Distribution from subsidiaries	316,027			10,435	(326,462)	
Distributions to partners	(343,771)					(343,771)
Debt issuance costs	(2,044)					(2,044)
Net cash provided by (used in) financing activities	819,706	103,695	(22,262)	(42,103)	(157,387)	701,649
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(3,082)	(38)	(22,276)	2,065	24,458	1,127
CASH AND CASH EQUIVALENTS, beginning of period	3,810	38	24,458	21,066	(24,458)	24,914
CASH AND CASH EQUIVALENTS, end of period	$ 728	$	$ 2,182	$ 23,131	$	$ 26,041

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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:

	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 2)	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	16,702	6,060	121,278	102,028
Total revenues	$ 9,293,868	$ 2,349,510	$ 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	$ 59,344	$ 13,629	$ 23,388	$ 15,744
Intrastate transportation and storage	84,701	20,670	56,145	42,477
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	$ 262,151	$ 71,333	$ 179,162	$ 117,415

Table of Contents

Index to Financial Statements

	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Years Ended August 31, 2007	Years Ended August 31, 2006
Operating Income (Loss):				
Midstream	$ 166,414	$ 73,167	$ 123,176	$ 151,507
Intrastate transportation and storage	718,348	172,120	488,098	430,698
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	(1,531)	(628)	1,735	1,899
Selling general and administrative expenses not allocated to segments	(4,892)	2,571	(3,270)	(17,288)
Total operating income	$ 1,117,579	$ 323,634	$ 829,652	$ 642,871
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (265,701)	$ (66,298)	$ (175,563)	$ (113,857)
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	(50,989)	(1,013)	31,032	
Allowance for equity funds used during construction	63,976	7,276	4,948	
Other, net	9,306	(5,202)	2,019	14,620
Income tax expense	(6,680)	(10,789)	(13,658)	(25,920)
Minority interests			(1,142)	(2,234)
	(251,556)	(61,810)	(153,513)	(127,019)
Net Income	$ 866,023	$ 261,824	$ 676,139	$ 515,852

	December 31, 2008	December 31, 2007
Total Assets:		
Midstream	$ 1,537,972	$ 1,304,187
Intrastate transportation and storage	4,642,430	3,976,895
Interstate transportation	2,487,078	1,834,941
Retail propane and other retail propane related	1,810,953	1,778,426
All other	149,056	113,712
Total	$ 10,627,489	$ 9,008,161

	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. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners under EITF 03-6 and variations in the weighted average units outstanding used in computing such amounts. Earnings per unit are computed on a stand-alone basis for each quarter and total year under EITF 03-6. HOLP s and Titan s businesses are seasonal due to weather conditions in their service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Sales to commercial and industrial customers are much less weather sensitive. ETC OLP s business is also seasonal due to the operations of ET Fuel 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 31	June 30	September 30	December 31	Total Year
Fiscal 2008:					
Revenues	$ 2,639,371	$ 2,653,476	$ 2,206,215	$ 1,794,806	$ 9,293,868
Gross profit	659,653	529,404	572,761	593,970	2,355,788
Operating income	373,486	225,829	260,508	257,756	1,117,579
Net income	328,335	165,674	221,048	150,966	866,023
Limited Partners interest in net income	253,971	86,691	140,796	68,669	550,127
Basic net income per limited partner unit	$ 1.34	$ 0.61	$ 0.93	$ 0.45	$ 3.75
Diluted net income per limited partner unit	$ 1.34	$ 0.60	$ 0.93	$ 0.45	$ 3.74

	Four Months Ended December 31
Transition Period:	
Revenues	$ 2,349,510
Gross profit	675,856
Operating income	323,634
Net income	261,824
Limited Partners interest in net income	170,813
Basic net income per limited partner unit	$ 1.22
Diluted net income per limited partner unit	$ 1.21

	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	107,842	358,362	191,308	172,140	829,652
Net income	71,032	311,114	157,466	136,527	676,139
Limited Partners interest in net income	17,731	250,547	97,504	74,481	440,263
Basic net income per limited partner unit	$ 0.15	$ 1.33	$ 0.71	$ 0.54	$ 3.32
Diluted net income per limited partner unit	$ 0.15	$ 1.33	$ 0.71	$ 0.54	$ 3.31

17. 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.

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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	45,824	83,978
Total revenues	2,349,510	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	71,333	48,767
Selling, general and administrative	59,132	40,603
Total costs and expenses	2,025,876	1,952,578
OPERATING INCOME	323,634	209,888
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(66,298)	(54,946)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other, net	1,061	2,158
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	272,613	164,055
Income tax expense	10,789	3,120
INCOME BEFORE MINORITY INTERESTS	261,824	160,935
Minority interests		(490)
NET INCOME	261,824	160,445
GENERAL PARTNER S INTEREST IN NET INCOME	91,011	73,204
LIMITED PARTNERS INTEREST IN NET INCOME	$ 170,813	$ 87,241
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.22	$ 0.70

BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	137,624,934	123,931,608
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.21	$ 0.70
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	138,013,366	124,229,968

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	2006
Net income	$ 261,824	$ 160,445
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17,269)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	21,626	152,653
Change in value of available-for-sale securities	(98)	(401)
Comprehensive income	$ 266,083	$ 288,999

165

Table of Contents

Index to Financial Statements

ENERGY TRANSFER PARTNERS, 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	$ 261,824	$ 160,445
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	71,333	48,767
Amortization in interest expense	1,435	1,068
Provision for loss on accounts receivable	544	563
Gain on disposal of assets	(14,310)	(2,212)
Non-cash unit-based compensation expense	8,114	4,385
Non-cash executive compensation	442	
Deferred income taxes	1,003	(2,234)
Distributions in excess of equity in earnings (losses) of affiliates, net	4,448	(4,743)
Other non-cash	(2,069)	414
Net change in operating assets and liabilities, net of acquisitions	(87,062)	214,457
Net cash provided by operating activities	245,702	420,910
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	1,741,547	1,667,810
Principal payments on debt	(1,062,272)	(1,737,788)
Net proceeds from issuance of Limited Partner Units	234,887	1,200,000
Capital contribution from General Partner	29	24,489
Distributions to partners	(175,977)	(125,774)
Debt issuance costs	(211)	(9,451)
Net cash provided by financing activities	738,003	1,019,286
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(12,238)	96,015
CASH AND CASH EQUIVALENTS, beginning of period	68,705	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 56,467	$ 122,056

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 acquistions	$	1,400	$	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid during the period for interest, net of interest capitalized	$	51,465	$	27,496
Cash paid during the period for income taxes	$	9,009	$	6,196

166

Table of Contents

Index to Financial Statements

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 Chief Executive Officer and Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosures. Our management including the Chief Executive Officer and Chief Financial Officer of our General Partner does not expect that our disclosure controls and procedures or our internal controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. The inherent limitations in all control systems include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a 15(e) and 15d 15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of 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 Partners, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer of our General Partner, and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO framework).

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.

Table of Contents

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited Energy Transfer Partners, L.P. s (a Delaware limited partnership) internal control over financial reporting as of 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 Partners, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Energy Transfer Partners, L.P. s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Energy Transfer Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of 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 Partners, 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

Table of Contents

Index to Financial Statements

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.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Partnership Management

Energy Transfer Partners GP, L.P. is our General Partner. Our General Partner manages and directs all of our activities. The activities of our General Partner are managed and directed by its general partner, ETP LLC. Our officers and directors are officers and directors of ETP LLC. The owners of the General Partner and ETP LLC may appoint up to eleven persons at least three of whom qualify as independent directors to serve on ETP LLC s Board of Directors. In addition, persons serving as ETP LLC s Chairman, President or Chief Executive Officer also serve on ETP LLC s Board of Directors. Each of these persons is individually a manager of ETP LLC, and are collectively referred to as our Board of Directors.

At all times during our 2008 year, our Board of Directors was comprised of 11 persons, eight of whom qualify as independent under the NYSE s corporate governance standards. We have determined that Messrs. Albin, Byrne, Collins, Glaske, Grimm, Harkey, Hersh and Turner are all independent under the NYSE s corporate governance standards.

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

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this report. In 2008, our Chief Executive Officer provided to the New York Stock Exchange the annual CEO certification regarding our compliance with the New York Stock Exchange s corporate governance listing standards.

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 Partnership and its Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Partnership. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders.

Table of Contents

Index to Financial Statements

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE s standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 401 of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee member Paul E. Glaske qualified as an Audit Committee financial expert during the Partnership s 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.

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 on the Audit 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 ETE. 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, our Board of Directors 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 the General Partner, the Partnership or its subsidiaries. Michael K. Grimm, Bill W. Byrne and Ray C. Davis 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.

Table of Contents

Index to Financial Statements

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. The Chairman of each of our Audit and Compensation Committee 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 independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of our General Counsel at Energy Transfer Partners, L.P., 3738 Oak Lawn Avenue, Dallas, Texas 75219 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

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 one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	53	Chief Executive Officer and Chairman of the Board of Directors
Mackie McCrea	49	President and Chief Operating Officer
J. Michael Howard	35	President Midstream
William G. Powers	55	President Propane
Martin Salinas, Jr.	37	Chief Financial Officer
Jerry J. Langdon	57	Chief Administrative and Compliance Officer
Thomas P. Mason	52	Vice President, General Counsel and Secretary
Ray C. Davis	67	Director
Bill W. Byrne	79	Director
David R. Albin	49	Director
Kenneth A. Hersh	46	Director
Paul E. Glaske	75	Director
K. Rick Turner	50	Director
Ted Collins, Jr.	70	Director
John W. McReynolds	58	Director
Michael Grimm	54	Director
John D. Harkey, Jr.	48	Director

Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:

Kelcy L. Warren. Mr. Warren is the sole Chief Executive Officer and Chairman of the Board of our General Partner and has served in

Table of Contents

Index to Financial Statements

that capacity since August 2007. Prior to that, Mr. Warren had served as the Co-Chief Executive Officer and Co-Chairman of the Board of our General Partner since the combination of the midstream and intrastate transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Warren served as President of the general partner of ET Company I, Ltd., having served in that capacity since 1996. From 1996 to 2000, he served as a director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 25 years of business experience in the energy industry.

Mackie McCrea. Mr. McCrea is the President and Chief Operating Officer of our General Partner and has served in that capacity since June 2008. Prior to that, he served as President Midstream of our General Partner from March 2007 to June 2008. Previously he served as the Senior Vice President Commercial Development since the combination of the operations of ETC OLP and HOLP in January 2004. In March 2005, Mr. McCrea was named president of ETC OLP. Prior to the combination of the operations of ETC OLP and HOLP, Mr. McCrea served as Senior Vice President Business Development and Producer Services of the General Partner of ETC OLP and ET Company I, Ltd., having served in that capacity since 1997.

J. Michael Howard. Mr. Howard is the President - Midstream of our General Partner and has served in that capacity since October 2008. Mr. Howard had previously served as the Chief Operating Officer of our midstream operations since June 2005. Prior to joining ETP, Mr. Howard served as Vice President of Engineering and Operations at Crosstex Energy, Inc. from August 2003 to June 2005. From 1993 to July 2003, Mr. Howard held various positions with Union Pacific Resources Group Inc. and its successor, DCP Midstream, LLC, ultimately serving as an Asset Manager for DCP Midstream, LLC s south Texas operations.

William G. Powers. Mr. Powers became President of Propane Operations (Heritage Propane) in May 2008, after serving as Chief Operating Officer Eastern US since June 2006. Mr. Powers joined Heritage Propane as Vice President of Northern Operations in March 2004. Prior to joining Heritage, Mr. Powers served as Executive Vice President and member of the office of President of Star Gas LLC, overseeing the heating oil division Petro. Mr. Powers was employed by Petro from 1984 to March 2002 and served in various capacities, including Regional Operations Manager, Vice President of Acquisitions, and President from November 1997 to March 2002. From December 1993 to November 1997, Mr. Powers served as President and CEO of Star Gas Corporation, a propane marketer and Petro subsidiary. Prior to joining Petro, Mr. Powers was employed by The Augsbury Corporation, a company engaged in the wholesale and retail distribution of fuel oils and gasoline.

Martin Salinas, Jr. Mr. Salinas has served as Chief Financial Officer of our General Partner since June 2008. Mr. Salinas had previously served as our Controller and Treasurer from September 2004 to June 2008. Prior to joining ETP, Mr. Salinas was a Senior Audit Manager with KPMG in San Antonio, Texas from September 2002.

Jerry J. Langdon. Mr. Langdon has served as the Chief Administration and Compliance Officer of our General Partner since June 2007. From 2003 until June 2007, Mr. Langdon served as Executive Vice President for Public and Regulatory Affairs and the Chief Compliance Officer for Reliant Energy, Inc. Prior to joining Reliant, Mr. Langdon served as the President of EPGT Texas Pipeline, L.P., a subsidiary of El Paso Corporation that owned and operated 8,000 miles of natural gas, NGL and LPG pipelines. Mr. Langdon also served for five years as a Commissioner of the FERC.

Thomas P. Mason. Mr. Mason has served as the Vice President, General Counsel and Secretary of our General Partner since June 2008. Mr. Mason served as General Counsel and Secretary of our General Partner since February 2007. Prior to joining ETP, he was a partner in the Houston office of Vinson & Elkins, where he had been working with Energy Transfer for the past several years. Mr. Mason has specialized in securities offerings and mergers and acquisitions for 25 years. Mr. Mason joined Vinson & Elkins as a partner in 2001 after a 19-year career at Andrews & Kurth, a Houston-based law firm.

Ray C. Davis. Mr. Davis was the Co-Chief Executive Officer and Co-Chairman of the Board of Directors of our General Partner since the combination of the midstream and intrastate transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004 until his retirement from these positions effective August 15, 2007. Mr. Davis also served as Co-Chief Executive Officer of the General Partner of ETC OLP and Co-Chairman of the Board of Directors of the General Partner of ETE, positions he held since their formation in 2002. Mr. Davis now serves as a director of the General Partners of ETP and ETE. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Davis served as Vice President of the General Partner of ET Company I, Ltd., the entity that operated ETC OLP s midstream assets before it acquired Aquila, Inc. s midstream assets, having

served in that capacity since 1996. From 1996 to 2000, he served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as Chairman of the Board of Directors and Chief Executive Officer of Cornerstone Natural Gas, Inc. Mr. Davis has more than 32 years of business experience in the energy industry. Mr. Davis became a venture partner of Natural Gas Partners, L.L.C. in September 2007.

Bill W. Byrne. Mr. Byrne is the principal of Byrne & Associates, LLC, an investment company based in Tulsa, Oklahoma. Prior to his retirement in 1992, Mr. Byrne was Vice President of Warren Petroleum Company, the gas liquids division of Chevron Corporation, serving in that capacity from 1982 to 1992. Mr. Byrne has served as a director of our General Partner since 1992 and is a member of both the Audit Committee and the Compensation Committee. Mr. Byrne is a former president and director of the National Propane Gas Association (NPGA).

David R. Albin. Mr. Albin is a managing partner of the Natural Gas Partners private equity funds, and has served in that capacity or similar capacities since 1988. Prior to his participation as a founding member of Natural Gas Partners, L.P. in 1988, he was a partner in the $600 million Bass Investment Limited Partnership. Prior to joining Bass Investment Limited Partnership, he was a member of the oil and gas group in the investment banking division of Goldman, Sachs & Co. He currently serves as a director of NGP Capital Resources Company. Mr. Albin has served as a director of our General Partner since February 2004 and has served as a director of LE GP, L.L.C. since October 2002.

Kenneth A. Hersh. Mr. Hersh is the Chief Executive Officer of NGP Energy Capital Management and is a managing partner of the Natural Gas Partners private equity funds and has served in those or similar capacities since 1989. Prior to joining Natural Gas Partners, L.P. in 1989, he was a member of the energy group in the investment banking division of Morgan Stanley & Co. He currently serves as a director of NGP Capital Resources Company and as a director of the general partner of Eagle Rock Energy Partners, L.P. Mr. Hersh has served as a director of our General Partner since February 2004 and has served as a director of LE GP, L.L.C. since October 2002.

Paul E. Glaske. Mr. Glaske retired as Chairman and Chief Executive Officer of Blue Bird Corporation, the largest manufacturer of school buses with manufacturing plants in three countries. Prior to becoming president of Blue Bird in 1986, Mr. Glaske served as the president of the Marathon LeTourneau Company, a manufacturer of large off-road mining and material handling equipment and off-shore drilling rigs. He 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 our General Partner since February 2004 and is chairman of the Audit Committee.

K. Rick Turner. Mr. Turner has been employed by Stephens family entities since 1983. He is currently Senior Managing Principal of The Stephens Group, LLC. He first became a private equity principal in 1990 after serving as the Assistant to the Chairman, Jackson T. Stephens. His areas of focus have been oil and gas exploration, natural gas gathering, processing industries, and power technology. Mr. Turner currently serves as a director of Atlantic Oil Corporation; SmartSignal Corporation; JV Industrials, LLC, JEBCO Seismic, LLC; North American Energy Partners Inc., Seminole Energy Services, LLC, BTEC Turbines LP, and the General Partner of ETP and the General Partner of ETE. Prior to joining Stephens, he was employed by Peat, Marwick, Mitchell and Company. Mr. Turner earned his B.S.B.A. from the University of Arkansas and is a non-practicing Certified Public Accountant.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. Mr. Collins previously served as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988, Mr. Collins was President of Enron Oil and Gas Company, and its predecessors, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quaser Petroleum Company. Mr. Collins is a director and serves on the Finance Committee of Hanover Compression Company, and is a director and the Chairman of the Governance Committee of Encore Acquisition Company. Mr. Collins has served as a director of our General Partner since August 2004.

John W. McReynolds. Mr. McReynolds is a director, and the President and Chief Financial Officer of Energy Transfer Equity, L.P. (ETE). Mr. McReynolds has served as the President of ETE since March 2005, and as a director and the Chief Financial Officer of ETE since August 2005. Prior to becoming President of ETE, Mr. McReynolds was a partner with the international law firm of Hunton & Williams LLP for over 20 years. As a lawyer, he specialized in energy-related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in numerous arbitration, litigation and government proceedings, including as an expert in special projects for boards of directors of public companies. Mr. McReynolds has served as a director of our General Partner since August 2004.

Michael K. Grimm. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and has served as its President and Chief Executive Officer since 1995. Prior to the formation of Rising Star, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for thirteen years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Houston Producers Forum, and Fort Worth Wildcatters. Mr. Grimm has served as a director of our General Partner since December 2005.

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 and member of the Audit Committee of ETE.

Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Partnerships. Our General Partner and its affiliates performing services for the Partnership and the Operating Partnerships are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to, but not paid directly by, the Partnership, if any, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Following the Energy Transfer Transactions in January 2004, the employees of the General Partner became employees of our Operating Partnerships, and thus, our General Partner has not incurred additional reimbursable costs since that time.

Compliance with Section 16(a) of the Securities and Exchange Act

Section 16(a) of the Securities and Exchange Act of 1934 requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership and changes in beneficial ownership with the Securities and Exchange Commission (SEC). Officers, directors and greater than 10% Unitholders are required by SEC regulations to furnish the General Partner with copies of all Section 16(a) forms.

Based solely on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during our year ended December 31, 2008, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, except as set forth below:

- late filing of a Form 4 for Mr. Glaske;
- late filing of a Form 4 for Mr. Powers;
- late filing of a Form 4 for Mr. Langdon;
- late filing of a Form 4 for Mr. Mason;
- late filing of a Form 4 for Mr. McCrea;

late filing of a Form 4 for Mr. Warren; and

late filing of a Form 4 for Mr. Grimm.

Table of Contents

Index to Financial Statements

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner, which in turn is managed by its general partner, ETP LLC., which we refer to in this Item 11 as our General Partner . ETE owns 100% of our General Partner and approximately 41% of our outstanding units. All of our employees are employed by and receive employee benefits from our subsidiary operating partnerships.

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of our management functions. As a result, the executive officers of our General Partner are essentially our executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The executive officers we refer to in this discussion as our named executive officers are the following officers of our General Partner:

- Kelcy L. Warren, Chief Executive Officer;
- Mackie McCrea, President 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.

In addition to the named executive officers identified above, the following individuals were executive officers of our General Partner 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 General Partner s Philosophy for Compensation of Executives

In general, our General Partner s philosophy for executive compensation is based on the premise that a significant portion of the executive s compensation should be incentive-based and that the base salary levels should be competitive in the marketplace for executive talent and abilities. Our General Partner also believes the incentives should be competitive in the market place and balanced between short and long-term performance. Our General Partner believes this balance is achieved by the payment of annual cash bonuses based on the achievement of financial performance objectives for a fiscal year set at the beginning of such fiscal year, and the annual grant of restricted unit awards under our equity incentive plans which are intended to provide a longer term incentive to our key employees to focus their efforts to increase the market price of our publicly traded units and to increase the cash distribution we pay to our Unitholders. Under the 2004 Unit Plan, we have issued restricted unit awards that vest over a three-year period based on the achievement of annual performance objectives relating to the total return of our units (defined as the appreciation in market price for our units plus total amount of cash distributions for our fiscal year) as compared to the total return of a peer group of other publicly traded limited partnerships determined by the compensation committee of our General Partner. Commencing in 2007, we 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. Our General Partner believes that these equity-based incentive arrangements are important in attracting and retaining our executive officers and key employees as well as motivating these individuals to achieve our business objectives. The equity-based compensation also reflects our importance of aligning the interests of the executive officers with those of our Unitholders.

While we are responsible for the direct payment of the compensation of our named executive officers as employees of ETP, ETP does not participate or have any input in any decisions as to the compensation policies of our General Partner or the compensation levels of the executive officers of our General Partner. As discussed below, ETP does not have a compensation committee. The compensation committee of the board of directors of our General Partner (the Compensation Committee) is responsible for the approval of the

Table of Contents

Index to Financial Statements

compensation policies and the compensation levels of these executive officers. We directly incur the payment to these executive officers in lieu of receiving an allocation of overhead related to executive compensation from our General Partner. For the year ended December 31, 2008, we paid 100% of the compensation of the executive officers of our General Partner as we represent the only business managed by our General Partner.

Our General Partner is ultimately controlled by the general partner of Energy Transfer Equity, L.P. (ETE), which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our partnership agreement with respect to its ownership of a 2% general partner interest and the incentive distribution rights specified in our partnership agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our partnership agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner s executive officers. Our General Partner s distribution rights are described in detail in Note 6 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

For a more detailed description of the compensation of our named executive officers, please see Compensation Tables below.

Compensation Committee

We are a limited partnership and our 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 our General Partner has established a Compensation Committee that is composed of two directors of our General Partner (Messrs. Byrne and Grimm) who our General Partner has determined to be independent (as that term is defined in the applicable NYSE corporate governance standards) and one director (Mr. Davis) who is not independent under the NYSE standards.

The Compensation Committee s responsibilities include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of the Chief Executive Officer, or the CEO;

- annually evaluate the CEO s performance in light of these goals and objectives, and make recommendations to the board of directors of our General Partner with respect to the CEO s compensation levels based on this evaluation;

- based on input from, and discussion with, the CEO, make recommendations to the board of directors of our General Partner with respect to non-CEO executive officer compensation, including incentive compensation and compensation under equity based plans;

- make determinations with respect to the grant of equity-based awards to executive officers under our 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 our General Partner.

Table of Contents

Index to Financial Statements

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- attract, retain and reward talented executive officers and key management employees, by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based compensation; and
- reward individual performance.

Methodology

The Compensation Committee considers relevant data available to it to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The Compensation Committee also considers individual performance, levels of responsibility, skills and experience.

Components of Executive Compensation

For the year ended December 31, 2008, the compensation paid to our named executive officers, other than our CEO, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- vesting of previously issued equity-based awards issued pursuant to our 2004 Unit Plan;
- compensation resulting from the vesting of equity issuances made by an affiliate; and
- 401(k) plan contributions.

Mr. Warren, our 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 engaged Mercer Consulting Services to assist in the determination of compensation levels 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 our named executive officers in order to assure competitiveness of the compensation of our 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, our numerical average of, the compensation levels at these other companies. In addition to this information, the Compensation Committee 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 our named executive officers in achieving this financial performance and in developing and executing projects for ETP s future growth.

Base Salary. As discussed above, the base salaries of our named executive officers for the year ended December 31, 2008 were determined by the board of directors of our General Partner 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 our General Partner. In May 2008, the Board of Directors of our 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 our 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 Partnership.

Table of Contents

Index to Financial Statements

Annual Bonus. In addition to base salary, we award our named executive officers, other than our CEO, 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 our named executive officers 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 our profitability and success during the year for which the bonuses are awarded. In this regard, the Compensation Committee takes into account whether the Partnership 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 our CEO in determining the specific cash bonus amounts for each of the other named executive officers. The Compensation Committee considers the recommendation of our CEO in determining the specific cash bonus amounts for each of the other named executive officers.

For our fiscal year ended August 31, 2007, the Compensation Committee approved a cash bonus for each of our named executive officers, other than our CEO, based in part upon the Partnership 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 our named executive officers, other than our CEO, based in part upon the Partnership s success in exceeding its internal financial budget for such four-month period. In each case, the budgets for such periods were presented to the Board of Directors of our 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 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 our named executive officers ranging from 100% to 150% of their annual salary. The individual bonus amounts for each named executive officer, other than our CEO, also reflect the Compensation Committee s view of the impact of such individual s efforts and contributions towards (i) achievement of the Partnership s success in exceeding its internal financial budget, (ii) the development of new projects that are expected to result in increased cash flows from operations in future years and (iii) the overall management of the Partnership s business.

Equity Awards. Each of our 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 our units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by each such plan. The Compensation Committee determined and/or approved the terms of the unit grants awarded to our named executive officers, 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 our units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the Compensation Committee, 65% of such one-third vesting if the total return of our units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of our units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of our units for the year plus the aggregate per unit cash distributions received for the year. For the twelve-month period ended August 31, 2008, the peer group used to make the total return comparison consisted of Suburban Propane Partners, L.P., Plains All American Pipeline, L.P., NuStar Energy L.P., Sunoco Logistics Partners L.P., Magellan Midstream Partners, L.P., AmeriGas Partners, L.P., ONEOK Partners, L.P., Buckeye Partners, L.P., Kinder

Table of Contents

Index to Financial Statements

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 us or our 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 our 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 employee unit awards, including unit awards granted to our named executive officers.

We have 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. In October 2008 and December 2008, the Compensation Committee approved the grant of new unit awards under our 2004 Unit Plan and our 2008 Incentive Plan to approximately 275 of our employees, including certain of our 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 Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. Of our named executive officers, 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 Partnership 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 Common Units pursuant to our equity incentive 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 Common Units.

The unit awards under our 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 our equity incentive plans, except for 10,583 unvested units held by Mr. Mills that were accelerated upon his retirement in May 2008.

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 the President of our General Partner, of certain rights related to units of ETE previously issued by ETE to such officer. These awards were granted as an inducement for these persons to accept employment with the Partnership and as an incentive to these persons to contribute to the Partnership s success. 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, 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 GAAP covering related party transactions and unit-based compensation arrangements, we are recognizing non-cash unit-based compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded the ETP employees assuming no forfeitures. 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.

Table of Contents

Index to Financial Statements

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. We have established a defined contribution 401(k) plan which covers substantially all of our employees including our named executive officers. The plan is subject to the provisions of the Employee Retirement Income Security Act of 1974 (ERISA). Employees who have completed one hour of service and have attained age 21 years of age are eligible to participate. Employees may elect to defer up to 100% of defined eligible compensation after applicable taxes, as limited under the Code. We may contribute to the plan on behalf of our employees under a discretionary matching or a discretionary profit sharing arrangement, both of which are based on a percentage of compensation. Employee salary deferrals are always 100% vested. Employer contributions vest upon completion of one year of service. For the year ended 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 executive officers, may participate in our health and welfare benefit programs including medical coverage and disability insurance.

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner. Each of our 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 these 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 unit awards that would fully vest upon a change of control as defined in our 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 do not have any deferred compensation arrangements or defined benefit pension plans or other post retirement benefits for our named executive officers. Our named executive officers also do not receive any payments that would represent a perquisite.

Director Compensation

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. On October 17, 2006, the Compensation Committee recommended, following its receipt and review of an independent third-party compensation study, and the Board of Directors approved, an amendment to the 2004 Unit Plan to provide that annual grants of ETP Common Units to non-employee directors of our General Partner will be equal to $25,000 divided by the fair market value of Common Units on 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 our General Partner approved the adoption of the 2008 Incentive Plan, subject to approval of our Unitholders. In December 2008, our Unitholders approved the 2008 Incentive Plan. The 2008 Incentive Plan provides for annual grants of ETP Common Units to non-employee directors of our General Partner equal to $50,000 divided by the fair market value of our Common Units as of each anniversary of December 16, 2008, the date of the adoption of the 2008 Incentive Plan.

Table of Contents

Index to Financial Statements

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

We account for our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), in accordance with the requirements of SFAS No. 123R over the vesting period of the awards, as discussed further in Note 6 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm, Byrne and Davis served on the Compensation Committee during 2008. During 2008, none of the members of the committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company s board of directors. In addition, neither Mr. Grimm nor Mr. Byrne are former employees of ours or any of our subsidiaries. Mr. Davis is associated with business entities with which we 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 Partners, L.P. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the

Board of Directors of Energy Transfer Partners, L.L.C., the

general partner of the Energy Transfer Partners GP, L.P.,

the general partner of Energy Transfer Partners, L.P.

Michael K. Grimm

Bill W. Byrne

Ray C. Davis

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.

Table of Contents

Index to Financial Statements

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 ($) (4)	Total ($)
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	Transition	177,926	200,000	106,355				5,327	489,608
Operating Officer	2007	380,769	600,000	150,303				14,481	1,145,553
Martin Salinas, Jr. (6) Chief Financial Officer									
	2008	261,539		239,000				1,557,912	2,058,451
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	Transition	265,105	200,000					701,815	1,166,920
Officer	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 for our named executive officers to be paid for calendar year 2008 have not yet been determined. We recorded accruals for the total bonus estimated for our named executive officers for calendar year 2008. The annual bonuses for our 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 our 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 our 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.

Table of Contents

Index to Financial Statements

(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 ($)
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	Transition				5,327				5,327
Operating Officer	2007				14,481				14,481
Martin Salinas, Jr.(6) Chief Financial Officer	2008				12,769			1,314,743	1,327,512
Jerry J. Langdon	2008							1,521,183	1,521,183
Chief Administrative	Transition							649,228	649,228
and Compliance Officer	2007							324,614	324,614
Thomas P. Mason	2008				5,480			2,435,684	2,441,164
Vice President, General	Transition				6,462			1,309,672	1,316,134
Counsel and Secretary	2007							2,478,593	2,478,593
Brian J. Jennings (7)	2008				4,615			348,600	353,215
Former Chief Financial	Transition				4,615			697,200	701,815
Officer	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.

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.

Table of Contents

Index to Financial Statements

(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 our 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

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards 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)
Kelcy L. Warren Chief Executive Officer	11/01/06		15,000	15,000			$	$ 406,490
Mackie McCrea President and Chief Operating Officer	12/22/08				20,000			681,800
	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) Chief Financial Officer	12/22/08				20,000			681,800
	10/07/08				1,501			45,465
Jerry J. Langdon Chief Administrative and	12/22/08				12,000			409,080
Compliance Officer	12/05/07				12,000			497,990
Thomas P. Mason Vice President, General Counsel and Secretary	12/22/08				20,000			681,800
	10/17/08				50,000			1,651,000
	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.

(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 7 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 2004 Unit Plan or the 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.

Table of Contents

Index to Financial Statements

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)**
Kelcy L. Warren Chief Executive Officer	2006		$	5,000	$ 170,050
Mackie McCrea President and Chief Operating Officer	2008			20,000	680,200
	2007			17,600	598,576
	2006			3,668	124,749
Martin Salinas, Jr. Chief Financial Officer	2008			20,000	680,200
	2007			4,800	163,248
	2006			1,334	45,369
Jerry J. Langdon Chief Administrative and Compliance Officer	2008			12,000	408,120
	2007			9,600	326,496
Thomas P. Mason Vice President, General Counsel and Secretary	2008			70,000	2,380,700
	2007			14,400	489,744
Brian J. Jennings Former Chief Financial Officer					

(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 2004 Unit Plan or the 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.

Table of Contents

Index to Financial Statements

Option Exercises and Units Vested Table

		Unit Awards	
Name	**Year (1)**	**Number of Units Acquired on Vesting (#)**	**Value Realized on Vesting ($) (2) (3)**
Kelcy L. Warren	2008	2,000	$ 73,660
Chief Executive Officer	Transition	3,500	131,673
	2007	9,000	523,702
Mackie McCrea	2008	19,483	668,064
President and Chief Operating Officer	Transition	2,917	109,740
	2007	7,999	465,457
Martin Salinas, Jr. (4)	2008	5,450	186,310
Chief Financial Officer			
Jerry J. Langdon	2008	2,400	73,704
Chief Administrative and Compliance Officer	Transition		
	2007		
Thomas P. Mason	2008	3,600	110,556
Vice President, General Counsel and Secretary	Transition		
	2007		
Brian J. Jennings	2008		
Former Chief Financial Officer	Transition		
	2007		

(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 2004 Unit Plan or the 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.

Table of Contents

Index to Financial Statements

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).

Non-Employee, Independent Director Compensation Table

Name	Year (1)	Fees Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)	Total ($)
Bill W. Byrne	2008	71,800	22,510		94,310
	2007	68,000	19,003		87,003
Paul E. Glaske	2008	69,400	22,510		91,910
	2007	66,150	22,207		88,357
K. Rick Turner	2008	43,793	22,510		66,303
	2007	51,050	28,532		79,582
Ted Collins, Jr.	2008	40,000	22,510		62,510
	2007	40,000	25,874		65,874
John W. McReynolds (2)	2007		8,177		8,177
Michael Grimm	2008	49,415	26,805		76,220
	2007	44,800	33,352		78,152
John D. Harkey, Jr.	2008	64,400	26,805		91,205
	2007	55,300	33,352		88,652
David R. Albin	2008				
	2007				
Kenneth A. Hersh	2008				
	2007				

(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.

In fiscal year 2008, non-employee directors of our General Partner received an annual fee of $40,000 plus $1,200 for each committee meeting attended. Additionally, the Chairman of the Audit Committee receives an annual fee of $15,000 and the members of the audit committee receive an annual fee of $10,000. The Chairman of the Compensation Committee receives an annual fee of $7,500 and the members of the compensation committee receive an annual fee of $5,000. Employee directors, including Messrs. Warren and McReynolds do not receive any fees for service as directors. The total amount of director fees we paid during 2008 to the directors of our General Partner was $384,728.

In fiscal year 2007, non-employee directors of our General Partner received an annual fee of $40,000 plus $1,200 for each committee meeting attended. Additionally, the Chairman of the Audit Committee receives an annual fee of $15,000 and the members of the audit committee receive an annual fee of $10,000. The Chairman of the Compensation Committee receives an annual fee of $7,500 and the members of the compensation committee receive an annual fee of $5,000. Employee directors, including Messrs. Warren and Davis (prior to August 15, 2007) did not receive any fees for service as directors during the periods presented. The total amount of director fees we paid during fiscal year 2007 to the directors of our General Partner was $325,300.

In addition, the non-employee directors have participated in our 2004 Unit Plan. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, ETP, or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election

Table of Contents

Index to Financial Statements

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 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 unit awards vest. 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 our General Partner approved the adoption of the 2008 Incentive Plan, subject to approval of our Unitholders. In December 2008, our Unitholders approved the 2008 Incentive Plan. The 2008 Incentive Plan provides for annual grants of ETP Common Units to non-employee directors of our General Partner equal to $50,000 divided by the fair market value of our 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 our units, reduced by the present value of the distributions that will not be received during the vesting period. We assumed a weighted average risk-free interest rate of 3.34% 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. For the Director Awards granted during the years ended December 31, 2008 and August 31, 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 Director Grants vested and 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

The following table sets forth in tabular format, a summary of certain information related to our 2004 Unit Plan and our 2008 Incentive Plan 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:			
Restricted Unit Plan	1,610	$	
2004 Unit Plan	1,055,454		16,847
2008 Incentive Plan	223,345		4,776,655
Equity compensation plans not approved by security holders			
Total	1,280,409	$	4,793,502

Table of Contents

Index to Financial Statements

Energy Transfer Partners, 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 named executive officers of the General Partner of our General Partner as a group, of our Common Units and Class E Units. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Title of Class	Name and Address of Beneficial Owner (1)	Beneficially Owned (2)	Percent of Class
Common Units	Kelcy L. Warren (3)	20,510	*
	Martin Salinas, Jr.	9,052	*
	Mackie McCrea(3)	43,732	*
	Jerry J. Langdon	1,766	*
	Thomas P. Mason	2,648	*
	William G. Powers	18,715	*
	Ray C. Davis (3)	53,170	*
	Bill W. Byrne	161,946	*
	David R. Albin (4)	10	*
	Kenneth A. Hersh (4)	10	*
	Paul E. Glaske	81,715	*
	Michael K. Grimm	17,706	*
	John D. Harkey, Jr.	2,530	*
	K. Rick Turner (4)	10,632	*
	Ted Collins, Jr.	99,972	*
	John W. McReynolds	17,987	*
	All Directors and Named Executive Officers		*
	as a Group (16 persons)	542,101	*
	ETE (5)	62,500,797	39.31%
Class E Units	Heritage Holdings, Inc. (6)	8,853,832	100%

* Less than one percent (1%)

(1) The address for Mr. Warren is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Heritage Holdings is 8801 S. Yale Avenue, Suite 310, Tulsa, Oklahoma 74137. The address for Messrs. Albin and Hersh is 125 E. John Carpenter Freeway, Suite 600, Irving, Texas 75062. The address for Mr. McCrea is 800 E. Sonterra Blvd., San Antonio, Texas 78258. The address for ETE and Mr. McReynolds is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Mr. Davis is 5950 Sherry Ln., Suite 550, Dallas, Texas 75225. The address for Messrs. Byrne, Grimm, Collins, Glaske, Harkey, and Turner is 3738 Oak Lawn Avenue, Dallas, Texas 75219.

(2) Beneficial ownership for the purposes of the foregoing table is defined by Rule 13d-3 under the Securities Exchange Act of 1934. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof (Voting Power) or to dispose or direct the disposition thereof (Investment Power) or has the right to acquire either of those powers within sixty (60) days.

(3) Due to the ownership by Messrs. Warren, McCrea and Davis of interests in ETE, they may be deemed to beneficially own the limited partnership interests held by ETE, to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

Table of Contents

Index to Financial Statements

(4) Each of Messrs. Albin, Hersh, and Turner are representatives of or owners in entities owning interests in ETE and may be deemed to beneficially own the limited partnership interest held by ETE though any such deemed ownership is not depicted in the table.

(5) ETE owns all of the member interests of Energy Transfer Partners, L.L.C and all of the Class A limited partner interests and Class B limited partner interests in Energy Transfer Partners GP, L.P. Energy Transfer Partners, L.L.C. is the General Partner of Energy Transfer Partners, GP, L.P. with a .01% General Partner interest. LE GP, LLC, the General Partner of ETE may be deemed to beneficially own the Common Units owned of record by ETE. The sole members of LE GP, LLC include Ray C. Davis, Kelcy L. Warren, and Enterprise GP Holdings, L.P.

(6) Energy Transfer Partners, L.P. indirectly owns 100% of the common stock of Heritage Holdings, Inc.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS,

AND DIRECTOR INDEPENDENCE

Our natural gas midstream operations secure compression services from third parties. Energy Transfer Technologies, Ltd. is one of the entities from which 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. Our Chief Executive Officer, Kelcy L. Warren has an indirect ownership interest in, and one of our 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, two of our directors, Ted Collins, Jr. and John W. McReynolds, serve on the Board of Directors of the ETG Entities. The terms of each arrangement to provide compression services are negotiated at an arms-length basis by management and are reviewed and approved by the Audit Committee. During the year ended 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 us. Fees recognized since the inception of this agreement were nominal.

On February 2, 2006 we entered into a shared services agreement effective upon the initial public offering of ETE. Under the terms of the shared services agreement, ETE will pay us an annual administrative fee of $0.5 million for the provision of various general and administrative services. The administrative fee may increase in the third year by the greater of 5% or the percentage increase in the consumer price index and may also increase if ETE later requires an increase in the level of general and administrative services. Fees recognized since the inception of this agreement were nominal.

On November 1, 2006, ETE purchased the remaining 50% of ETP s Incentive Distribution Rights from Energy Transfer Investments, L.P. (ETI). Also on November 1, 2006, we sold and issued to ETE approximately 26.1 million of our Class G Units for $1.20 billion (see Note 6 to our consolidated financial statements for additional information). After the November 1, 2006 transactions and the conversion of our Class F Units to Common Units (see Note 6 to our consolidated financial statements) ETE owns directly and indirectly the 2% General Partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights and 62,500,797 ETP Common Units.

Table of Contents

Index to Financial Statements

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)	$ 3,490,000	$ 1,922,000	$ 3,279,000
Audit related fees (2)	60,000		
Tax fees (3)			14,250
All other fees (4)		5,000	60,000
Total	$ 3,550,000	$ 1,927,000	$ 3,353,250

(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.

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 93.
(2) Financial Statement Schedules None.
(3) Exhibits see Index to Exhibits set forth on page E-1.

Table of Contents

Index to Financial Statements

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY TRANSFER PARTNERS, L.P.

By Energy Transfer Partners GP, L.P,
its general partner.

By Energy Transfer Partners, L.L.C.,
its general partner

By: /s/Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer and officer duly
authorized to sign on behalf of the registrant

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 27, 2009
/s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer (Principal Financial and Accounting Officer)	February 27, 2009
/s/ Ray C. Davis Ray C. Davis	Director	February 27, 2009
/s/ Bill W. Byrne Bill W. Byrne	Director	February 27, 2009
/s/ David R. Albin David R. Albin	Director	February 27, 2009
/s/ Kenneth A. Hersh Kenneth A. Hersh	Director	February 27, 2009
/s/ Paul E. Glaske Paul E. Glaske	Director	February 27, 2009

/s/ K. Rick Turner K. Rick Turner	Director	February 27, 2009
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	February 27, 2009
/s/ John W. McReynolds John W. McReynolds	Director	February 27, 2009
/s/ Michael K Grimm Michael K. Grimm	Director	February 27, 2009
/s/ John D. Harkey, Jr. John D. Harkey, Jr.	Director	February 27, 2009

Table of Contents

Index to Financial Statements

INDEX TO EXHIBITS

The exhibits listed on the following Exhibit Index are filed as part of this report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

	Exhibit Number	Description
(58)	2.1	Contribution Agreement dated as of September 22, 2008 by and among Energy Transfer Partners, L.P. and OGE Energy Corp.
(1)	3.1	Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(18)	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.)
(18)	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.)
(26)	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.)
(27)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(34)	3.1.9	Amendment No. 9 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(35)	3.1.10	Amendment No. 10 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(36)	3.1.11	Amended and Restated Amendment No. 11 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(37)	3.1.12	Amendment No. 12 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(1)	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.

Table of Contents

Index to Financial Statements

	Exhibit Number	Description
(44)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(44)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(17)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.
(18)	4.2	Unitholder Rights Agreement dated January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.
(21)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(22)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors names therein and Wachovia Bank, National Association, as trustee.
(28)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(30)	4.9	Third Supplemental Indenture dated as of July 29, 2005 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(32)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(32)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
(42)	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.
(33)	4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(51)	4.15	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.
(48)	4.16	Seventh Supplemental Indenture dated December 23, 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.
(35)	4.17	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(45)	10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC as senior managing agents, and other lenders party hereto.
(1)	10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)	10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.

Table of Contents

Index to Financial Statements

		Exhibit Number	Description
(3)		10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
(5)		10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.
(6)		10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(9)		10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)		10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(11)		10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(46)		10.2.8	364-Day Term Loan Agreement, dated as of October 5, 2007, by and among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, and certain other lenders party thereto.
(50)		10.2.9	364-Day Term Loan Agreement, dated as of February 5, 2008, by and among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, and certain other lenders party thereto.
(43)	+	10.6.6	Amended and Restated 2004 Unit Plan.
(39)	+	10.6.7	Midstream Bonus Plan.
(49)	+	10.6.8	Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan.
(4)		10.16	Note Purchase Agreement dated as of November 19, 1997.
(5)		10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.
(6)		10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(7)		10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(8)		10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(11)		10.16.5	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(19)		10.16.6	Sixth Amendment Agreement dated as of November 18, 2003 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(8)		10.19	Note Purchase Agreement dated as of August 10, 2000.
(11)		10.19.1	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)		10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.

Table of Contents

Index to Financial Statements

	Exhibit Number	Description
(19)	10.19.3	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(24)	10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(25)	10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(38)	10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(40)	10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(41)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(42)	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.
(44)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(44)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(44)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(52)	10.57	Credit Agreement, dated as of February 29, 2008, by and among Midcontinent Express Pipeline LLC, The Royal Bank of Scotland plc, as the administrative agent, and certain other lenders party thereto.
(53)	10.58	Guaranty Agreement, dated as of February 29, 2008, between Energy Transfer Partners, L.P., as the guarantor, and The Royal Bank of Scotland plc, as the administrative agent.
(*)	21.1	List of Subsidiaries.
(*)	23.1	Consent of Grant Thornton LLP.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Table of Contents

Index to Financial Statements

	Exhibit Number	Description
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	99.1	Financial Statements of Energy Transfer Partners GP, L.P. as of December 31, 2008
(*)	99.2	Financial Statements of Energy Transfer Partners, L.L.C. as of December 31, 2008

* Filed herewith.
** Furnished herewith.
\+ Denotes a management contract or compensatory plan or arrangement.
(1) Incorporated by reference to Exhibit 3.2 to Registrant s Registration Statement on Form S-1, File No. 333-04018, filed with the Commission on June 21, 1996.
(2) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1996.
(3) Incorporated by reference to Exhibit 10.2.1 to Registrant s Form 10-Q for the quarter ended February 28, 1997.
(4) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1997.
(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1998.
(6) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1999.
(7) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2000.
(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated August 23, 2000.
(9) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2000.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.
(11) Incorporated by reference to Exhibit 10.2.7 to the Registrant s Form 10-Q for the quarter ended February 28, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(13) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2001.

(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated February 13, 2002.
(18) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(19) Incorporated by reference to Exhibit 10.2.8 to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(21) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed January 19, 2005.
(22) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed January 19, 2005.
(23) Incorporated by reference to Exhibit 4.3 to the Registrant s Form 8-K filed January 19, 2005.
(24) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed February 1, 2005.
(25) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed February 1, 2005.
(26) Incorporated by reference to Exhibit 3.1.7 to the Registrant s Form 8-K filed March 16, 2005.
(27) Incorporated by reference to Exhibit 3.1.8 to the Registrant s Form 8-K filed February 9, 2006.
(28) Incorporated by reference to Exhibit 10.45 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(29) Incorporated by reference to Exhibit 10.39.1 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(30) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed August 2, 2005.
(31) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed August 2, 2005.
(32) Incorporated by reference to the same numbered Exhibit to the Registrant s Form S-3 filed on August 9, 2006.
(33) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed October 25, 2006.
(34) Incorporated by reference to Exhibit 3.1.9 to the Registrant s Form 8-K filed May 3, 2006.
(35) Incorporated by reference to Exhibit 3.1.10 to the Registrant s Form 8-K filed November 3, 2006.
(36) Incorporated by reference to Exhibit 3.1.11 to the Registrant s Form 8-K filed January 18, 2008.
(37) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed April 24, 2008.
(38) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed September 18, 2006.

(39) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed March 3, 2008.
(40) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed September 18, 2006.
(41) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed September 18, 2006.
(42) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2006.
(43) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended June 30, 2008.
(44) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2007.
(45) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed on July 23, 2007.
(46) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed on October 9, 2007.
(47) Incorporated by reference to Exhibit 2.1 to the Registrant s Form 8-K/A filed September 26, 2008.
(48) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed on December 23, 2008.
(49) Incorporated by reference to Exhibit A to the Proxy Statement filed by the Registrant on November 21, 2008.
(50) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed on February 7, 2008.
(51) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed on March 31, 2008.
(52) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed on March 4, 2008.
(53) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed on March 4, 2008.