Energy Transfer Partners, L.P.
Form 10-K
February 24, 2010

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2009

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 Ö 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 _Ö_

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 _Ö_ No ___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ___ 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.

Large accelerated filer _Ö_ 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_Ö_

The aggregate market value as of June 30, 2009, of the registrant s Common Units held by non-affiliates of the registrant, based on the reported closing price of such units on the New York Stock Exchange on such date, was $4.28 billion. 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 16, 2010, the registrant had 189,242,287 Common Units outstanding.

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PART I

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by us in periodic press releases and some oral statements of our officials during presentations about us, include certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (Securities Act) and Section 21E of the Securities Exchange Act of 1934 (Exchange Act). 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 expressions help identify forw 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 units
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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ITEM 1. BUSINESS

Overview

We (Energy Transfer Partners, L.P., a Delaware limited partnership, ETP or the Partnership) are one of the largest publicly traded master limited partnerships in the United States in terms of equity market capitalization (approximately $8.46 billion as of February 11, 2010). We are managed by our general partner, 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., a publicly traded master limited partnership (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 operating subsidiaries (collectively referred to as the Operating Companies) 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), ETC Fayetteville Express Pipeline, LLC (ETC FEP) and ETC Tiger Pipeline, LLC (ETC Tiger). ET Interstate is 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 Companies, and their subsidiaries are collectively referred to in this report as we, us, ETP, Energy Transfer or the Partnership.

Significant Achievements in 2009 and Beyond

Our significant 2009 achievements included the following, as discussed in more detail herein:

Generated revenues of approximately $5.42 billion, operating income of approximately $1.13 billion and net income of approximately $791.5 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 1,000 miles of large diameter pipeline ranging from 36 inches to 42 inches with approximately 5 Bcf/d of natural gas transportation capacity during 2009. These pipeline completions, coupled with our existing pipeline systems, further enhance our natural gas transportation capabilities to and from the most prolific producing areas in the United States of America. Below is information about some of our more significant completed expansion projects.

Project		Capacity	Miles	Completion Date
36	Southern Shale	700 MMcf/d	31	January 2009
36	Cleburne to Tolar	400 MMcf/d	20	January 2009
36	Katy expansion	400 MMcf/d	56	February 2009

Phoenix lateral	500 MMcf/d	260	February 2009
42 Texas Independence Pipeline	1.1 Bcf/d	143	August 2009

Completed construction of the Midcontinent Express pipeline, an approximately 500-mile interstate natural gas pipeline that originates near Bennington, Oklahoma, is routed through Perryville, Louisiana, and

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terminates at an interconnect with Transcontinental Gas Pipeline Corporation s, or Transco s interstate natural gas pipeline in Butler, Alabama. The pipeline has a current capacity of 1.4 Bcf/d on Zone 1 and 1.0 Bcf/d on Zone 2, all of which has been committed pursuant to predominantly 10-year firm transportation contracts with shippers. The pipeline has also received long-term transportation contracts related to additional capacity that is planned to be added through the utilization of additional compression. The planned capacity expansions to 1.8 Bcf/d on Zone 1 and 1.2 Bcf/d on Zone 2 are expected to completed in the latter part of 2010. Midcontinent Express pipeline is a 50/50 joint venture with Kinder Morgan Energy Partners, L.P. (KMP).

Completed several financing transactions despite challenging market conditions, including:

- The issuance of $1.0 billion aggregate principal amount of Senior Notes in April 2009.
- The issuance of an aggregate of 23,575,000 Common Units from offerings in January 2009, April 2009 and October 2009.
- The issuance of 1,891,691 Common Units during November and December 2009 under an equity distribution program, as described in Note 7 to our consolidated financial statements.
- The issuance of $350.0 million aggregate principal amount of Senior Notes at Transwestern in December 2009.

In addition, in January 2010, we issued 9,775,000 Common Units through a public offering. The proceeds from these transactions were used primarily to repay borrowings under our revolving credit facility and to fund capital expenditures related to pipeline projects.

Recent Developments and Current Growth Projects

Fayetteville Express Pipeline LLC

In October 2008, we entered into a 50/50 joint venture with KMP for the development of the Fayetteville Express pipeline, an approximately 185-mile 42-inch 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. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. In December 2009, Fayetteville Express Pipeline LLC (FEP), the entity formed to own and operate this pipeline, received approval of its application for Federal Energy Regulatory Commission (FERC) authority to construct and operate this pipeline. The only request for rehearing of FERC s authorization is a limited one related to a discrete rate issue filed by FEP itself. Subject to final resolution of this issue, the pipeline is expected to be in service by the end of 2010. 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 Kinder Morgan, Inc., which owns the general partner of KMP. Our estimate of the total costs of this project is approximately $1.2 billion.

Tiger Pipeline

In January 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 an approximately 180-mile 42-inch interstate natural gas pipeline (Tiger pipeline). 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, with interconnects to at least seven interstate pipelines at various points in Louisiana.

The agreement with Chesapeake provides for a 15-year commitment for firm transportation capacity of approximately 1.0 Bcf/d. We have also entered into agreements with EnCana Marketing (USA), Inc., a subsidiary of EnCana Corporation and other shippers that provide for 10-year commitments for firm

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transportation capacity on the Tiger pipeline, bringing the initial design capacity to 2.0 Bcf/d in the aggregate, which is expected to be in service in the first half of 2011. In February 2010, we announced that we had entered into a 10-year commitment for an additional 400 MMcf/d. The ultimate capacity of the expansion, which is expected to be completed in the second half of 2011, will be based on producer response during a binding open season.

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline, which is pending necessary regulatory approvals. We expect the total costs of this project to be $1.2 billion, excluding the costs of the recently announced expansion. The ultimate cost will depend on the results of the binding open season.

Segment Overview

Our segments and business are as described below. See Note 15 to our consolidated financial statements for additional financial information about our segments.

Intrastate Transportation and Storage Segment

Through our intrastate transportation and storage segment, we own and operate approximately 7,800 miles of natural gas transportation pipelines and three natural gas storage facilities located in the state of Texas.

Through ETC OLP, we own the largest intrastate pipeline system in the United States with interconnects to Texas markets and 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 segment accounted for approximately 56%, 65% and 59% of our total consolidated operating income for the years ended December 31, 2009, December 31, 2008 and August 31, 2007, respectively. 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 market price and resold to customers based on an index price. In addition, our intrastate transportation and storage segment generates revenues from fees charged for storing customers working natural gas in our storage facilities and from margin from managing natural gas for our own account.

Interstate Transportation Segment

Through our interstate transportation segment, we own and operate approximately 2,700 miles of interstate natural gas pipeline, with an additional 180 miles under construction. In addition, we have interests in joint ventures that have 500 miles of interstate natural gas pipeline and 185 miles under construction.

Our interstate transportation segment accounted for approximately 12%, 11% and 12% of our total consolidated operating income for the years ended December 31, 2009, December 31, 2008 and August 31, 2007, respectively. The results from our interstate transportation segment are primarily derived from the fees earned from natural gas transportation services and operational gas sales. In addition, our joint ventures contributed $17.6 million of our income before income taxes for the year ended December 31, 2009.

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Midstream Segment

Through our midstream segment, we own and operate approximately 7,000 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 and are integrated with our intrastate transportation and storage assets.

Our midstream segment accounted for approximately 12%, 14% and 15% of our total consolidated operating income for the years ended December 31, 2009, December 31, 2008 and August 31, 2007, respectively. 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.

Retail Propane Segment

We are one of the three largest retail propane marketers in the United States based on gallons sold and serve more than one million customers through a nationwide retail distribution network consisting of 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 segment accounted for approximately 20%, 10% and 15% of our total consolidated operating income for the years ended December 31, 2009, December 31, 2008 and August 31, 2007, respectively. The retail propane segment is a margin-based business in which gross profits depend on the excess of sales price over propane supply cost. Consequently, the profitability of our retail propane business is sensitive to changes in wholesale propane prices. Our propane business is largely seasonal and dependent upon weather conditions in our service areas, as discussed further in Retail Propane Segment - Industry Overview.

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Natural Gas Operations Asset Overview

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

Intrastate Transportation and Storage Segment

The following details our pipelines and storage facilities in the intrastate transportation and storage segment.

ET Fuel System

- Capacity of 5.2 Bcf/d
- Approximately 2,570 miles of natural gas pipeline
- 2 storage facilities with 12.4 Bcf of total working gas capacity

The ET Fuel System serves some of the most active drilling areas in the United States and is comprised of approximately 2,570 miles of intrastate natural gas pipeline and related natural gas storage facilities. Included in the ET Fuel System is the Texas Independence pipeline, which was completed in August 2009. 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

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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 5.2 Bcf/d. The major shippers on our pipelines include XTO Energy, Inc., EOG Resources, Inc., Chesapeake Energy Marketing, Inc., Encana Marketing (USA), Inc. and Quicksilver Resources, Inc.

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. All of our storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements.

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

Oasis Pipeline

- Capacity of 1.2 Bcf/d
- Approximately 600 miles of natural gas pipeline
- Connects Waha to Katy market hubs

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 (i) providing access for natural gas on the Southeast Texas System to other third party supply and market points and interconnecting pipelines and (ii) allowing us to bypass our processing plants and 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.

Houston Pipeline System (HPL System)

- Capacity of 5.5 Bcf/d
- Approximately 4,300 miles of natural gas pipeline
- Bammel storage facility with 62 Bcf of total working gas capacity

The HPL System is comprised of approximately 4,300 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 including the strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers 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.

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The Bammel storage facility has a total working gas capacity of approximately 62 Bcf, a peak withdrawal rate of 1.3 Bcf/d and a peak injection rate of 0.6 Bcf/d. The Bammel storage facility is 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. As of December 31, 2009, we had approximately 25.4 Bcf committed under fee-based arrangements with third parties and approximately 27.6 Bcf stored in the facility for our own account.

East Texas Pipeline

- Capacity of 2.4 Bcf/d
- Approximately 370 miles of natural gas pipeline

The East Texas pipeline is a 370-mile natural gas pipeline that connects three treating facilities, one of which we own, with our Southeast Texas System. The East Texas 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 expansions include the 36-inch East Texas extension to connect our Reed compressor station in Freestone County to our Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting our Cleburne to Carthage pipeline to the HPL system. Key shippers on the East Texas pipeline include XTO and EnCana with an average of 420,000 MMBtu/d and 540,000 MMBtu/d, respectively.

Interstate Transportation Pipelines

The following details our pipelines in the interstate transportation segment.

Transwestern Pipeline

- Capacity of 2.1 Bcf/d
- Approximately 2,700 miles of interstate natural gas pipeline

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 Phoenix lateral pipeline completed in February 2009, 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 (NGA) and is subject to the regulatory jurisdiction of the FERC.

The Phoenix lateral pipeline consists of 260 miles of 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.

Midcontinent Express Pipeline

- Current capacity of 1.4 Bcf/d on Zone 1 (placed in service in April 2009) and 1.0 Bcf/d on Zone 2 (placed in service in August 2009)
- Planned capacity expansion to 1.8 Bcf/d on Zone 1 and 1.2 Bcf/d on Zone 2
- Approximately 500 miles of interstate natural gas pipeline
- 50/50 joint venture with KMP

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We constructed, 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 originates near Bennington, Oklahoma, is routed through Perryville, Louisiana, and terminates 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 has a current capacity of 1.4 Bcf/d, all of which capacity has been committed pursuant to firm transportation contracts with shippers for periods ranging from 5 to 10 years. The pipeline has also received long-term transportation contracts related to an additional 0.4 Bcf/d of capacity on Zone 1 and 0.2 Bcf/d of capacity on Zone 2 that is planned to be added through the utilization of additional compression. The first Zone of the pipeline, from Bennington, Oklahoma to Perryville, Louisiana, was placed in service in April 2009, and the second Zone of the pipeline from Perryville, Louisiana to Butler, Alabama was placed in service in August 2009. The expansion projects are expected to be completed in the latter part of 2010.

Fayetteville Express Pipeline

- Initial planned capacity of 2.0 Bcf/d (expected to be in service by the end of 2010)
- Approximately 185 miles of interstate natural gas pipeline
- 50/50 joint venture with KMP

See additional description of FEP included in Recent Developments above.

Tiger Pipeline

- Initial planned capacity of 2.0 Bcf/d (expected to be in service in the first half of 2011)
- Planned expansion of not less than 0.4 Bcf/d (expected to be completed in the second half of 2011)
- Approximately 180 miles of interstate natural gas pipeline

See additional description of Tiger pipeline included in Recent Developments above.

Midstream

The following details our assets in the midstream segment.

Southeast Texas System

- 5,200 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

The Southeast Texas System is a 5,200-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, 11 treating facilities and 4 conditioning facilities. This system is connected to the Katy Hub through the East Texas pipeline and is also connected to the Oasis pipeline, as well as two power plants. This allows us to bypass our processing plants and treating facilities when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with natural gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

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.

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Our 11 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. In addition, 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.

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

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. 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.

Canyon Gathering System

- 1,390 miles of natural gas pipeline
- 6 natural gas conditioning facilities with aggregate capacity of 90 MMcf/d

The Canyon Gathering System consists of approximately 1,390 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 aggregate capacity of 90 MMcf/d.

Other Midstream Assets

The midstream segment also includes our interests in various midstream assets located in Texas, New Mexico and Louisiana, with gathering pipelines aggregating a combined capacity of approximately 470 MMcf/d, as well as one processing facility.

Marketing Operations

We market the natural gas that flows through our assets, referred to as on-system gas, and also use our marketing operation to 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.

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.

Other Natural Gas Operations

Effective August 17, 2009, we acquired 100% of the membership interests of Energy Transfer Group, L.L.C. (ETG), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. (ETT). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP.

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In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.

Business Strategy

We have designed our business strategy with the goal of increasing 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 balance our desire for growth with our goal of preserving a strong balance sheet, strong liquidity and investment grade credit metrics.

We expect that acquisitions in natural gas operations will be the primary focus of our acquisition strategy going forward, 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.

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 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.

Propane Business Strategies

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

Growth through complementary acquisitions. We believe that our position as one of the three largest propane marketers in the United States provides us a solid foundation to continue our acquisition growth strategy through consolidation.

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

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Natural Gas Operations Segments

Industry Overview

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

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

Demand for natural gas. Natural gas continues to be a critical component of energy consumption in the United States. According to data released in December 2009 by the Energy Information Administration, or the EIA, total domestic consumption of natural gas is expected to remain steady through 2035, with average annual consumption of 23.1 Tcf during that period, compared to 2009 consumption of 22.6 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 collects natural gas from points near producing wells and transports it to larger pipelines for further transportation.

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

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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 reduce 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.

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 and have remained at low levels due to the continued effects of the economic recession and higher than normal storage levels. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells.

We are diligent in attempting to ensure that we issue credit to credit-worthy customers. However, our purchase and resale of gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss could be significant to our overall profitability.

During the year ended December 31, 2009, none of our customers individually accounted for more than 10% of our midstream, intrastate transportation and storage and interstate segment revenues.

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Regulation

Regulation by the FERC of Interstate Natural Gas Pipelines. The FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the Natural Gas Act (NGA), the 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 the FERC s regulatory jurisdiction. We have applied to the FERC for authority to construct, own and operate the Tiger pipeline. We also hold interests in two joint venture projects involving the construction and operation of interstate pipelines: Midcontinent Express pipeline, which was placed into full service in August 2009, and Fayetteville Express pipeline. Subject to possible rehearing and judicial review, the Fayetteville Express pipeline is expected to be in service by the end of 2010. Midcontinent Express pipeline is an NGA-jurisdictional interstate transportation system subject to the FERC s broad regulatory oversight. Assuming the FERC grants the certificates of public convenience and necessity authorizing the construction, ownership and operation of the Tiger pipeline, the Tiger and the Fayetteville Express pipelines will likewise be NGA-jurisdictional once placed into operation.

The 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, the FERC approved a Stipulation and Agreement of Settlement (Stipulation and Agreement) that resolved primary components of the rate case. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. 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 charged on the Midcontinent Express pipeline are largely governed by long-term negotiated rate agreements, an arrangement approved by the FERC in its July 25, 2008 order granting MEP the certificate of public convenience and necessity to build, own and operate these facilities. In the certificate order, the FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates. On December 17, 2009, the FERC issued an order granting FEP authorization to construct and operate the Fayetteville Express pipeline, subject to certain conditions, and FEP accepted the FERC s certificate. Subject to possible rehearing and judicial review, the pipeline is expected to be in service by late 2010. The rates to be charged for services on the Fayetteville Express pipeline will largely be governed by long-term negotiated rate agreements, an arrangement approved by the FERC in its December 17, 2009 certificate order. In the certificate order, the FERC also approved cost-based recourse rates available to prospective shippers as an alternative to

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negotiated rates. The application for a certificate of public convenience and necessity to construct the Tiger pipeline was filed with the FERC on August 31, 2009. The FERC has not yet issued an order authorizing the construction of the pipeline and the rate-related arrangements for the services to be provided on these facilities.

The rates to be charged by NGA-jurisdictional natural gas companies are generally required to be on file with the 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 the FERC. Rate increases proposed by the interstate natural gas company may be challenged by protest or by the FERC itself, and if such proposed rate increases are found unjust and unreasonable may be rejected by the 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 guarantee that the 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, the 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 the 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 (CEA). 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 the 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 the FERC review and approval. Should the 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 the

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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.

The FERC has adopted 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 the FERC s NGA jurisdiction such as natural gas marketers. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve the FERC s ability to assess market forces and detect market manipulation. The FERC also requires certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information. As these posting requirements are currently on appeal before the U.S. 5th Circuit Court of Appeals, it is not known with certainty the precise form these requirements will ultimately take. Full compliance with these regulations could subject us to further costs and administrative burdens, none of which are expected to have a material impact on our operations.

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the Texas Railroad Commission (TRRC). 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.

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC s regulations and policies, or with an interstate pipeline s tariff, could result in the imposition of civil and criminal penalties.

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. The 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 the 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 the 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 the FERC uses to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between the 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 the FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation.

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

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

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

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

Retail Propane Segment

Industry Overview

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

Propane is extracted from natural gas at processing plants or separated from crude oil during the refining process. Propane is normally transported and stored in a liquid state under moderate pressure or refrigeration for ease of

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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.

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 also affected by 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.

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

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

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Products, Services and Marketing

Our customer service locations are typically located 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 in 2009, approximately 56% were to residential customers, 29% were to industrial, commercial and agricultural customers and 15% were to other retail users. While sales to residential customers in 2009 accounted for 56% of total retail gallons sold, they accounted for approximately 67% 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 2009, with all other retail users accounting for 12%. No single propane customer accounted for 10% or more of consolidated revenues in 2009.

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 40 energy companies and natural gas processors at numerous supply points located in the United States and Canada. In 2009, Enterprise Products Operating L.P. (Enterprise) and Targa Liquids Marketing and Trade (Targa) provided approximately 50.3% and 14.3% 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 the majority of its propane from Enterprise pursuant to an agreement that expires in 2010 and contains renewal and extension options. Substantially all agreements with Targa have a maximum duration of one year.

In addition, we have a propane purchase agreement with M.P. Oils, Ltd. that expires in 2015, which provided 15.1% of our combined total propane supply during 2009.

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 2009. Although we cannot

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guarantee 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 agreements with Enterprise and 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, 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, NGLs 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 did not comply with permit terms.

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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 guarantee 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 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

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liabilities. As of December 31, 2009 and 2008, accruals of $12.6 million and $13.3 million, respectively, were recorded in our consolidated balance sheets 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 $8.6 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. 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 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 (TCEQ) is scheduled to develop a plan by April 2010 to respond to the re-designation of the Houston area from a moderate to a severe ozone non-attainment area. By March 2013, TCEQ is required to develop another plan to address the recent change in the ozone standard from 0.08 ppm to 0.075 ppm and the EPA recently proposed to lower the standard even further, to somewhere between 0.060 and 0.070 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, there are a number of parallel initiatives to restrict or regulate emissions of greenhouse gases. On June 26, 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap and trade program to reduce domestic emissions of greenhouse gases. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions or suppliers of carbon-based fuels so that such sources could continue to emit greenhouse gases into the atmosphere or market such fuels. The market price of these allowances would be expected to increase significantly over time, thereby encouraging the use of alternative energy sources or greenhouse gas emission control technologies by imposing ever-increasing costs on the use of carbon-based fuels, including NGLs, natural gas, refined petroleum products, and oil. The United States Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. At the state level, 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 programs operate similarly to the program contemplated by ACESA. Depending on the particular program, we could be required to purchase and surrender 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 or NGLs) 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*, EPA was required to determine whether greenhouse gas emissions posed an endangerment to human health and the environment and whether emissions from mobile sources, such as cars and trucks contributed to that endangerment. On December 7, 2009, the EPA announced its findings that emissions of greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere causing other climatic changes and that mobile sources are contributing to such endangerment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, EPA proposed two sets of regulations in anticipation of finalizing its endangerment finding: one to reduce emissions of greenhouse gases from motor vehicles and the other to control emissions of greenhouse gases from stationary sources. Although the motor vehicle rules are expected to be adopted in March 2010, it may take EPA several years to impose regulations limiting emissions of greenhouse gases from stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including NGL fractionators and local natural gas distribution companies. Any federal greenhouse gas legislation is expected to prevent EPA from regulating greenhouse gases under existing Clean Air Act regulatory programs to some extent, but if Congress fails to pass greenhouse gas legislation, the EPA is expected to continue its announced greenhouse gas regulatory actions under the Clean Air Act. Any limitation on emissions of greenhouse gases from our equipment and operations or the requirement that we obtain allowances for such emissions, as well as the NGLs that we produce, could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or acquire allowances at the prevailing rates in the marketplace.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our propane and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market the fuels that we produce. Despite the use of the term global warming as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience substantially colder temperatures than their historical averages. As a result, it is difficult to predict how the market for our fuels would be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

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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. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. 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.

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.

On December 21, 2009, the Colorado Department of Public Health and Environment Air Pollution Control Division (the Division) issued a Compliance Order on Consent (the Consent Order) pursuant to which the Division determined that ETC Canyon Pipeline, LLC (ETC Canyon) violated certain of its operating and construction permits and Colorado air quality statutes at two natural gas processing plants located in Rio Blanco County, Colorado. In full and final resolution of those matters, ETC Canyon agreed to pay a penalty of $0.2 million. The entry into the Consent Order does not constitute an admission by ETC Canyon of any of the factual or legal determinations of the Division. The Consent Order also requires ETC Canyon to perform testing of the thermal oxidizers at one of its facilities to demonstrate compliance with emissions limits. Following this performance testing, the Division will determine whether it is appropriate to address certain additional issues identified by the Division. We cannot predict what course of action the Division will take; however, we do not expect any future penalties related to this matter to have a material impact on our financial position, results of operations or cash flows.

Employees

As of January 31, 2010, we employed 1,334 persons to operate our natural gas operations. We employed 4,247 full-time employees to operate our propane operations. Of the propane employees, 58 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.

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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 or furnish with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports on our Internet website located at http://www.energytransfer.com. 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 risks 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 in our 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 derivative activities.

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

- the level of capital expenditures we make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to make working capital borrowings under our credit facilities to make distributions;
- our ability to access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount, if any, of cash reserves established by our General Partner in its discretion for the proper conduct of our business.

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

Furthermore, Unitholders 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, 2009, ETE owned 62,500,797 ETP Common Units. ETE also 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.

In August 2009, we filed a registration statement to register 12,000,000 ETP Common Units held by ETE, which allows ETE to offer and sell these ETP Common Units to the public.

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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, 2009, we had approximately $6.22 billion of consolidated debt, excluding the credit facilities of our joint ventures, which we guarantee in part. 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 covenants of the debt agreements could negatively impact our ability and the ability of our subsidiaries to incur additional debt, including our ability to utilize the available capacity under our revolving credit facilities, and our ability to pay our distributions.

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, 2009, we had approximately $6.22 billion of total debt. 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, 2009, we had approximately $6.22 billion of total debt. Approximately $160.0 million of our consolidated debt bears interest at variable interest rates and the remainder bears interest at fixed rates. 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. As of December 31, 2009, we did not have any interest rate swaps outstanding.

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.

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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 indirect owners over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from 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 riskier 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.

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, 2009, ETE and its affiliates held approximately 33% of our outstanding units, with an additional approximate 1% of our outstanding 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 related parties.

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 to transfer 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 other than that of our operating subsidiaries. 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 Unitholders 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.

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 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, 2009, ETE and its affiliates directly and indirectly owned an aggregate limited partner interest in us of approximately 33% 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 are 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.

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 us.

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.

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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 may compete with us.

Except as provided in our Partnership Agreement, affiliates and related parties 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 currently has a 40.6% non-controlling equity interest in LE GP, LLC, ETE s general partner. Additionally, two directors of the general partner of Enterprise GP, including its Chairman, currently serve as directors LE GP, LLC. Enterprise GP 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 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 adverse effect on our results of operations and operating cash flows.

We are exposed to claims by third parties related to the claims that were previously brought against us by the FERC.

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 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 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). The FERC alleged that we 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. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. The FERC specified that it was also seeking to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices. In February 2008, the FERC s Enforcement Staff also recommended that the FERC pursue market manipulation claims related to our trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC s allegations in the Order and Notice, and that we 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.

On August 26, 2009, we entered into a settlement agreement with the FERC s Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement settles all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims against us, including existing litigation claims as well as any new claims that may be asserted against this fund. An administrative law judge appointed by the FERC will determine the validity of any third party claim against this fund. Any party who receives money from this fund will be required to waive all claims against us related to this matter. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by exceeding the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

We made the $5.0 million payment and established the $25.0 million fund in October 2009. The allocation of the $25.0 million fund is expected to be determined in 2010.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE alleging 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. In one of these cases, the Texas Supreme Court ruled on July 3, 2009 that the state district court erred in ruling that a plaintiff was entitled to pre-arbitration discovery and therefore remanded to the state district court with a direction to rule on our original motion to compel arbitration pursuant to the terms of the arbitration clause in a natural gas contract between us and the plaintiff. This plaintiff has filed a motion with the Texas Supreme Court requesting a rehearing of the ruling.

In February 2008, we were 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. This action is currently on appeal before the First Court of Appeals, Houston, Texas.

In October 2007, a consolidated 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 intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the CEA. It is further alleged that during the class period from 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 March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs motion for reconsideration. On September 28, 2009, these decisions were appealed by the plaintiffs to the United States Court of Appeals for the 5th Circuit, and the appeal is currently in briefing stage before the court.

In March 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 March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for antitrust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert a claim for common law fraud and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff s motion and granted our motion to dismiss the complaint. On September 10, 2009, this decision was appealed by the plaintiff to the United States Court of Appeals for the 5th Circuit, and the appeal is currently in briefing stage before the court.

We are expensing the legal fees, consultants fees and other expenses relating to these matters in the periods in which such costs are incurred. We do not have any accruals for litigation and other contingencies as of December 31, 2009. Although the $25.0 million fund required by the settlement agreement with the FERC is to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obliged to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the fund. 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 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.

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

Income from our midstream and intrastate transportation and storage operations 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 the 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, 2009, the NYMEX settlement price for the prompt month contract ranged from a high of $6.14 per MMBtu to a low of $2.84 per MMBtu. A composite of the Mt. Belvieu average NGLs price based upon our average NGLs composition during our year ended December 31, 2009 ranged from a high of approximately $1.17 per gallon to a low of approximately $0.57 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, which factors may result in decisions by natural gas producers to reduce production of natural gas during periods of lower prices for natural gas or may result in decisions by end-users of natural gas 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;

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- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

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

From time to time, we have sought to limit a portion of the adverse effects resulting from changes in natural gas and other commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by our marketing and/or system optimization activities. 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.

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

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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 revenues 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. If the reserves available through the supply basins connected to Transwestern s systems 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.

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

We may not be able to fully execute our growth strategy if we encounter 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 give assurance 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, 2009, our consolidated balance sheet reflected $745.6 million of goodwill and $206.4 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 capital and balance sheet leverage as measured by debt to total capitalization.

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

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

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

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

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

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;
- less effectively manage our historical assets, due to the diversion of management s attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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, Unitholders 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, at all, or at the budgeted cost. We currently have several major expansion and new build projects planned or underway, including 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 a particular project. 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.

For our year ended December 31, 2009, EnCana Oil and Gas (USA), Inc., XTO Energy Inc. (XTO), SandRidge Energy Inc., and EnerVest Operating, LLC, supplied us with approximately 70% of the Southeast Texas System s natural gas supply. In December 2009, Exxon Mobil Corporation (ExxonMobil) and XTO announced an agreement whereby ExxonMobil will acquire XTO. For our year ended December 31, 2009, Chesapeake Energy Marketing, Inc., XTO, EOG Resources, Inc., and EnCana Oil and Gas (USA), Inc., supplied us with approximately 84% 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 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. ExxonMobil s pending acquisition of XTO, expected to be completed in the second quarter of 2010, is not expected to result in any changes to these commitments. We also have an eight-year fee-based transportation contract with TXU Portfolio Management Company, L.P., a subsidiary of TXU Corp. (TXU Shipper) to transport natural gas on the ET Fuel System to TXU s electric generating power

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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 Energy or TXU Shipper to fulfill their contractual obligations under these contracts could have a material adverse effect on our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

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 2 to 11 years.

Transwestern generates the majority of its revenues from long-term and short-term firm transportation contracts with natural gas producers, local distribution companies and end-users. During 2009, ConocoPhillips, Salt River Project and BP Energy Company collectively accounted for 32% of Transwestern s total revenues.

The failure of the major shippers on our intrastate and interstate transportation pipelines 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, the joint venture entity formed to construct and operate the Midcontinent Express pipeline, has secured predominantly 10-year firm transportation contracts from a small number of major shippers for all of the current 1.4 Bcf/d of capacity on the Midcontinent Express pipeline. MEP has also secured firm transportation commitments related to additional capacity on the Midcontinent Express pipeline, which expansion was approved by the FERC in September 2009. The planned capacity expansions to 1.8 Bcf/d are expected to be completed in the latter part of 2010. FEP has secured binding 10-year commitments from a small number of major shippers 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. We have also entered into agreements with EnCana Marketing (USA), Inc. and other shippers that provide for 10-year commitments for firm transportation capacity on the Tiger pipeline, bringing the initial design capacity to 2.0 Bcf/d in the aggregate. In February 2010, we announced that we had entered into a 10-year commitment for an additional 400 MMcf/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 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 the 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, and failure to comply with the rates approved by the 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.

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FERC has adopted new market-monitoring and annual and quarterly 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, such as natural gas marketers. 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. These regulations may result in administrative burdens and additional compliance costs for us.

We hold transportation contracts with interstate pipelines that are subject to FERC regulation. As a shipper on an interstate pipeline, we are subject to FERC requirements related to use of the interstate capacity. Any failure on our part to comply with the FERC s regulations or orders could result in 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 Texas are subject to regulation as common purchasers and as gas utilities by the 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 TRRC-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.

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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 deemed just and reasonable by the FERC. The rates charged by natural gas companies are generally required to be on file with the 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 tariff rates. Further, rates must, for the most part, be cost-based and the FERC has the ability, on a prospective basis, to order refunds of amounts collected under rates that have been found by the FERC to be in excess of a just and reasonable level.

Transwestern made a general rate case filing under Section 4 of the NGA 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) have the statutory ability to challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint.

Most of the rates to be paid by the initial shippers on the Midcontinent Express pipeline are established pursuant to long-term, negotiated rate transportation agreements. Other prospective shippers on Midcontinent Express pipeline that elect not to pay a negotiated rate for service may opt instead to pay a cost-based recourse rate established by the 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. FERC applications for authorization to construct, own and operate the Fayetteville Express pipeline and the Tiger pipeline were filed on June 15, 2009 and August 31, 2009, respectively. On December 17, 2009, the FERC issued an order granting authorization to construct, own and operated the Fayetteville Express pipeline, subject to certain conditions. While FEP has accepted the FERC s certificate authorization, this order is subject to a limited request for rehearing and possible judicial review. FERC has not yet determined whether the Tiger pipeline should be granted the requested authority. We cannot predict if, or when and with what conditions, FERC authorization for the Tiger pipeline will be granted.

Any successful challenge to the rates of our interstate natural gas companies, whether brought by complaint, protest or investigation, could reduce our revenues associated with providing transportation services on a prospective basis. We cannot guarantee 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 the 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 the FERC and the courts for a number of years. It is currently the 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 the 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 the 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, the FERC s regulatory authority extends to many other aspects of the business and operations of our interstate pipelines, including:

- 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 and Tiger pipelines we have had to, among other things, file and support before FERC NGA Section 7(c) applications for certificates of public convenience and necessity to build, own and operate such facilities. Although the FERC has authorized the construction and operation of the Fayetteville Express pipeline, subject to certain conditions, this order is still subject to limited rehearing and possible judicial review. The FERC has not yet ruled upon the Tiger pipeline application, and we cannot guarantee that FERC will authorize construction and operation of that pipeline or any future interstate natural gas transportation project we might propose. Moreover, there is no guarantee that, if granted, certificate authority for the Tiger pipeline, or any future interstate projects, will be granted in a timely manner or will be free from potentially burdensome conditions.

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 the FERC has granted us such certificate authority, the FERC s certificate order is currently pending judicial review before the United States Court of Appeals for the District of Columbia Circuit. We cannot guarantee that the court will affirm, in all material respects, the FERC s July 25, 2008 Midcontinent Express certificate order, or that the FERC will not materially alter the certificate order on any remand that might be ordered by the court. There are also pending requests for rehearing related to certain of the FERC s post-certification orders related to the MEP project. We cannot guarantee that these post-certification orders will not be altered on rehearing or that these orders will not be subject to judicial review.

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, the 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. The 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 liabilities 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, personal injury or property damage. The total accrued future estimated cost of remediation activities relating to our Transwestern pipeline operations expected to continue through 2018 is $8.6 million.

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, requiring 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. The EPA recently proposed to lower the standard even further, to somewhere between 0.060 and 0.070 ppm. 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, there are a number of parallel initiatives to restrict or regulate emissions of greenhouse gases. On June 26, 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap and trade program to reduce domestic emissions of greenhouse gases. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions or suppliers of carbon-based fuels so that such sources could continue to emit greenhouse gases into the atmosphere or market such fuels. The market price of these allowances would be expected to increase significantly over time, thereby encouraging the use of alternative energy sources or greenhouse gas emission control technologies by imposing ever-increasing costs on the use of carbon-based fuels, including NGLs, natural gas, refined petroleum products, and oil. The United States Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. At the state level, 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

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development of emission inventories or regional greenhouse gas cap and trade programs. These programs operate similarly to the program contemplated by ACESA. Depending on the particular program, we could be required to purchase and surrender 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 or NGLs) 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*, EPA was required to determine whether greenhouse gas emissions posed an endangerment to human health and the environment and whether emissions from mobile sources, such as cars and trucks contributed to that endangerment. On December 7, 2009, the EPA announced its findings that emissions of greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere causing other climatic changes and that mobile sources are contributing to such endangerment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, EPA proposed two sets of regulations in anticipation of finalizing its endangerment finding: one to reduce emissions of greenhouse gases from motor vehicles and the other to control emissions of greenhouse gases from stationary sources. Although the motor vehicle rules are expected to be adopted in March 2010, it may take EPA several years to impose regulations limiting emissions of greenhouse gases from stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including NGL fractionators and local natural gas distribution companies. Any federal greenhouse gas legislation is expected to prevent EPA from regulating greenhouse gases under existing Clean Air Act regulatory programs to some extent, but if Congress fails to pass greenhouse gas legislation, the EPA is expected to continue its announced greenhouse gas regulatory actions under the Clean Air Act. Any limitation on emissions of greenhouse gases from our equipment and operations or the requirement that we obtain allowances for such emissions, as well as the NGLs that we produce, could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or acquire allowances at the prevailing rates in the marketplace.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our propane and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market the fuels that we produce. Despite the use of the term global warming as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience substantially colder temperatures than their historical averages. As a result, it is difficult to predict how the market for our fuels would be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

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

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

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We may be impacted by 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 and the Midcontinent Express pipeline (and upon completion the Fayetteville Express and Tiger pipelines) 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, access to sources of supply and the flexibility and reliability of service. Natural gas competes with other forms of energy available to our customers and end-users, including for example, electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the levels of natural gas transportation volumes in the areas served by our pipelines.

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

- price,
- reliability and quality of service,
- responsiveness to customer needs,
- safety concerns,
- long-standing customer relationships,

the inconvenience of switching tanks and suppliers, and

the lack of growth in the industry.

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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 extensions of existing and any 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. Transwestern s existing right-of-way agreements with the Navajo Nation, Southern Ute, Pueblo of Laguna and Fort Mojave tribes extend through November 2029, September 2020, December 2022 and April 2019, respectively.

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 the year ended December 31, 2009, approximately 26% of our sales of natural gas was to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are increasingly reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

Our storage business may depend 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.

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

Our pipeline operations are subject to regulation by the DOT, under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas. Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements will result in capital costs of $20.5 million and operating and maintenance costs of $20.4 million over the course of the next year. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. 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 and, accordingly, affect the market price of our Common Units.

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

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

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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.

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

During 2009, we purchased approximately 50.3%, 14.3% and 15.1% of our propane from Enterprise, Targa 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 the majority of its propane from Enterprise pursuant to an agreement that expires in 2010 and contains renewal and extension options. 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 for federal income tax purposes 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

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to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, 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.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. 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 their 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.

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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 United States federal income tax returns and generally pay tax on their share of our taxable income.

We treat each purchaser of Common Units as having the same tax benefits without regard to the 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) of the Internal Revenue Code. 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 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. 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. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Although publicly traded partnerships are entitled to rely on these proposed Treasury Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued.

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

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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.

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.

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 for all Unitholders which would require us to file two tax returns 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 calendar year, 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.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they 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 conduct 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.

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ITEM 2. PROPERTIES

Substantially all of our pipelines, which are described in Item 1, 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 own substantially all of the bulk storage facilities at our customer service locations for our propane operations 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 50.9 million gallons of above-ground storage capacity at our various propane plant sites and have leased an aggregate of approximately 15.0 million gallons of underground storage facilities in Michigan, Arizona, New Mexico and Texas and smaller storage facilities in other locations. We do not own or operate any underground propane storage facilities (excluding customer and local distribution tanks) or propane pipeline transportation assets (other than local delivery systems).

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

We own an office building for our executive office in Dallas, Texas and office buildings in Helena, Montana and San Antonio, Texas. We also own a field office building in Fruita, Colorado and lease office facilities in Houston, 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, 2009, we utilized approximately 172 transport truck tractors, 275 transport trailers, 19 railroad tank cars, 2,000 bobtails and 3,154 other delivery and service vehicles, all of which we own. As of December 31, 2009, 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

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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 Companies, or contemplated to be brought against us or our Operating Companies, under the various environmental protection statutes to which they are subject, except for the December 21, 2009 Compliance Order on Consent issued by the Colorado Department of Public Health and Environment Air Pollution Control Division, as discussed above under Item 1, Business Environmental Matters.

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

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PART II

ITEM 5. MARKET FOR 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 (the NYSE) 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 NYSE 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 2009			
Fourth Quarter Ended December 31, 2009	$ 45.56	$ 40.77	$ 0.89375
Third Quarter Ended September 30, 2009	47.44	38.70	0.89375
Second Quarter Ended June 30, 2009	44.33	36.50	0.89375
First Quarter Ended March 31, 2009	38.69	30.72	0.89375
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

(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.

Description of Units

As of February 16, 2010, there were approximately 152,000 individual Common Unitholders, which includes Common Units held in street name. Our Common Units represent limited partner interests in us that entitle the holders to the rights and privileges specified in our Second Amended and Restated Agreement of Limited Partnership (the Partnership Agreement). Our Common Units are registered under the Exchange Act, as amended, and are listed for trading on the NYSE. The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

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.

As of December 31, 2009, our General Partner owned an approximate 1.9% general partner interest in us and the holders of Common Units and Class E Units collectively owned a 98.1% limited partner interest in us.

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.

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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 and/or 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 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

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.

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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 $10.0 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, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received $0.25 per unit for such quarter (the minimum quarterly distribution);

Second, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received $0.275 per unit for such quarter (the first target cash distribution);

Third, 87% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, and 13% to the holders of Incentive Distribution Rights, pro rata, until each Common Unit has received at least $0.3175 per unit for such quarter (the second target cash distribution);

Fourth, 77% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, and 23% to the holders of Incentive Distribution Rights, pro rata, until each Common Unit has received at least $0.4125 per unit for such quarter (the third target cash distribution); and

Fifth, thereafter, 52% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, and 48% to the holders of Incentive Distribution Rights, pro rata.

The allocation of distributions among the Common and Class E Unitholders and the General Partner is based on their respective interests as of the record date for such distributions. As of December 31, 2009, the Common and Class E Unitholders collectively held 98.1% of the ownership interests in us, and the General Partner held a 1.9% interest.

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, to all of our Unitholders and to our General Partner, in accordance with their percentage interests, until we distribute for each Common Unit, an amount of available cash from capital surplus equal to our initial public offering price; and

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

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

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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 is reflected in Note 7 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The following table discloses purchases of our Common Units made by us or on our behalf for the quarter ended December 31, 2009.

Period	Total Number of Units Purchased(1)	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Purchased Under the Plans or Programs
October 1 - October 31	12,735	$ 42.28	N/A	N/A
November 1 - November 30	-	-	N/A	N/A
December 1 - December 31	55,707	43.32	N/A	N/A
Total	68,442	43.12	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 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, 2009, certain of the participants in the 2004 Unit Plan and the 2008 Long-Term Incentive 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.

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ITEM 6. SELECTED FINANCIAL DATA

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 financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical consolidated financial statements and the accompanying notes thereto included elsewhere in this report. The amounts in the table below, except per unit data, are in thousands.

	Years Ended December 31,		Four Months Ended December 31,	Years Ended August 31,		
	2009	2008	2007	2007	2006	2005
Statement of Operations Data:						
Revenues:						
Intrastate transportation and storage segment	$ 2,391,544	$ 5,634,604	$ 1,254,401	$ 3,915,932	$ 5,013,224	$ 2,608,108
Interstate transportation segment (a)	270,213	244,224	76,000	178,663	-	-
Midstream segment	2,441,160	5,342,393	1,166,313	2,853,496	4,223,544	3,246,772
Retail propane and other retail propane related segment	1,292,583	1,624,010	511,258	1,284,867	879,556	709,473
All other	21,665	16,702	6,060	121,278	102,028	75,700
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)	(2,359,256)	(471,255)
Total revenues	5,417,295	9,293,868	2,349,510	6,792,037	7,859,096	6,168,798
Gross margin	2,295,239	2,355,788	675,856	1,713,831	1,290,780	787,283
Depreciation and amortization	312,803	262,151	71,333	179,162	117,415	92,943
Operating income	1,127,607	1,117,579	323,634	829,652	642,871	312,051
Interest expense, net of interest capitalized	394,274	265,701	66,298	175,563	113,857	93,017
Income from continuing operations before income tax expense	804,319	872,703	272,613	690,939	544,006	209,409
Income tax expense (b)	12,777	6,680	10,789	13,658	25,920	7,295
Income from continuing operations	791,542	866,023	261,824	677,281	518,086	202,114
Basic income from continuing operations per unit (c)	2.53	3.74	1.24	3.32	3.61	1.79
Diluted income from continuing operations per limited partner unit (c)	2.53	3.74	1.24	3.31	3.60	1.79
Cash distribution per unit (d)	3.58	3.55	1.13	3.19	2.56	1.89
Balance Sheet Data (at period end):						
Current assets	1,271,963	1,183,401	1,409,959	1,041,093	1,301,804	1,446,572
Total assets	11,734,972	10,627,489	9,008,161	7,708,428	5,455,013	4,415,458
Current liabilities	823,539	1,150,547	1,215,461	924,217	1,016,490	1,239,426
Long-term debt, less current maturities	6,176,918	5,618,549	4,297,264	3,626,977	2,589,124	1,675,705
Equity	4,599,708	3,743,069	3,379,191	3,042,072	1,738,719	1,343,336
Other Financial Data:						

Cash flows provided by operating activities	826,878	1,258,145	245,702	1,112,732	543,884	169,418
Cash flows used in investing activities	(1,345,756)	(2,015,585)	(995,943)	(2,158,090)	(1,244,406)	(1,133,749)
Cash flows provided by financing activities	495,159	792,875	738,003	1,088,022	701,649	907,500
Capital expenditures:						
Maintenance (accrual basis)	102,652	140,968	48,998	89,226	51,826	41,054
Growth (accrual basis)	530,333	1,921,679	604,371	998,075	677,861	155,405
Cash (received in) paid for acquisitions	(30,367)	84,783	337,092	90,695	586,185	1,131,844

(a) Our interstate transportation operations began in fiscal 2007 with the acquisition of Transwestern pipeline.

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

(c) See Note 5 to our consolidated financial statements for a discussion of the computation of income per limited partner unit. Amounts have been restated due to the retrospective application of accounting principles adopted in 2009.

(d) The cash distribution per unit for fiscal year 2006 includes the special SCANA distribution of $0.0325 per unit related to the proceeds we received in connection with the settlement and litigation.

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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.

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 amounts 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 caused 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. In 2009, we completed several projects, including the Texas Independence Pipeline in August 2009. 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 conducted in the following segments:

- Intrastate transportation and storage - Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline on an interruptible basis. The fee structure consists of a monetary fee and/or fuel retention. Excess fuel retained after consumption is sold at market prices. Our 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.

We generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we utilize our excess storage capacity to inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term to describe a pricing environment, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering a financial derivative to lock in the sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result, under fair value hedge accounting, changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread.

In addition to hedging our stored natural gas, we also use financial derivatives to lock in prices on a portion of our estimated volumes exposed to natural gas price risk within our intrastate transportation segment.

During 2009, we also entered into financial derivatives to lock in spreads on a portion of our transportation system s open capacity. Margins earned on that open capacity are dependent on price differentials at different points on our system, generally from West Texas to East Texas. We account for these financial derivatives using mark-to-market accounting and the change in value of these derivatives are recorded in earnings. As of December 31, 2009, approximately 3.4% of our capacity is hedged.

Interstate transportation - Revenue is primarily generated by fees earned from natural gas transportation services and operational gas sales.

Midstream - Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

In addition to fee-based contracts for gathering, treating and processing, we also have percent of proceeds and keep-whole contracts, which are subject to market pricing. For percent of proceeds contracts (which generally account for approximately 11% of total processed volumes), we retain a portion of the natural gas and NGLs processed as a fee. When natural gas and NGL pricing increase, the value of the percent we retain as a fee increases. Conversely, when prices of natural gas and NGL s decrease, so does the value of the portion we retain as a fee. For keep-whole contracts (which account for approximately 24% of total processed volumes), we retain the difference between the price of NGLs and the cost of the gas to process it. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could be negative. In the event it is uneconomical to process this gas, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs.

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.

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

Trends and Outlook

Economic forecasts indicate continued high storage levels combined with slow consumption growth are expected to keep natural gas prices from rising dramatically throughout 2010. We have mitigated much of the exposure to changing prices and demand within our operations. In our natural gas operations, a significant portion of our revenue continues to be derived from long-term fee-based arrangements, pursuant to which our customers pay us

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capacity reservation fees regardless of the volume of natural gas transported; however, we do recognize a portion of our revenue from fees based on actual volumes transported. In addition, we continue to evaluate and execute strategies to mitigate the impacts of changing prices. For example, during the second half of 2009, we began entering into hedges to lock in prices on a portion of our estimated volumes exposed to natural gas price risk within our intrastate transportation segment. These volumes include net retained fuel and a portion of volumes purchased at the wellhead from producers and sold at market prices. Approximately 79% of our estimated volumes exposed to natural gas price risk in 2010 is currently hedged.

With our liquid take-away capacity, we anticipate a slight increase in volumes of NGLs processed in 2010. We believe this will have a favorable impact on our fee-based business as producers will be motivated to take advantage of the favorable pricing.

As a result of the industry-specific and general economic challenges encountered in the recent past, we maintained our quarterly distributions to our Unitholders at a consistent rate throughout 2009. We believe that this approach has been prudent and also in the best interest of our Unitholders. However, we are committed to our primary objective of increasing the level of our cash distributions, and in order to do so, we are continuing our pursuit of growth through construction of new assets, expansion of our existing assets and through strategic acquisitions. To that end, we currently expect to spend between $1.2 billion and $1.3 billion for growth capital expenditures in 2010. We believe that we have sufficient liquidity to fund our announced growth projects in 2010; furthermore, we believe that our current liquidity position would provide us the financial flexibility to pursue accretive acquisitions of various sizes, if such opportunities arise that we believe are in the best interests of our Unitholders.

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, a new 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 calendar years ended December 31, 2009 and 2008, the four-month periods ended December 31, 2007 and 2006 and the fiscal year ended August 31, 2007.

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 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 years ended December 31, 2009 and 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. Since certain activities involve the purchase and sale of

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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 trading of financial derivative instruments that are not offset by physical positions 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, 2009 Compared to the Year Ended December 31, 2008 (tabular dollar amounts are expressed in thousands)

Consolidated Results

	Years Ended December 31,		
	2009	2008	Change
Revenues	$ 5,417,295	$ 9,293,868	$ (3,876,573)
Cost of products sold	3,122,056	6,938,080	(3,816,024)
Gross margin	2,295,239	2,355,788	(60,549)
Operating expenses	680,893	781,831	(100,938)
Depreciation and amortization	312,803	262,151	50,652
Selling, general and administrative	173,936	194,227	(20,291)
Operating income	1,127,607	1,117,579	10,028
Interest expense, net of interest capitalized	(394,274)	(265,701)	(128,573)
Equity in earnings (losses) of affiliates	20,597	(165)	20,762
Losses on disposal of assets	(1,564)	(1,303)	(261)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	90,228
Allowance for equity funds used during construction	10,557	63,976	(53,419)
Other, net	2,157	9,306	(7,149)
Income tax expense	(12,777)	(6,680)	(6,097)
Net income	$ 791,542	$ 866,023	$ (74,481)

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

Interest Expense. Interest expense increased principally due to higher levels of borrowings, which were used to finance growth capital expenditures primarily in our intrastate transportation and storage and interstate transportation segments, including capital contributions to our joint ventures.

Equity in Earnings (Losses) of Affiliates. The increase in equity in earnings of affiliates between the periods was primarily attributable to earnings of MEP, which was placed in service in 2009. We recorded equity in earnings of MEP of $14.0 million during 2009.

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Gains (Losses) on Non-Hedged Interest Rate Derivatives. We had interest rate swaps with a notional amount of $625.0 million outstanding at December 31, 2008, all of which were settled or terminated during 2009. As of December 31, 2009, we did not have any interest rate swaps outstanding. The losses during 2008 primarily relate to changes in the fair value of forward starting interest rate swaps as a result of a sharp decline in the 10-year LIBOR swap rate, while the gains in 2009 resulted from increases in the index rate prior to settlement.

Allowance for Equity Funds Used During Construction. The decrease in the allowance of equity funds used was due to the completion of the Phoenix project in February 2009.

Other Income, Net. The decrease between the periods was primarily due to contributions in aid of construction, which exceeded our project costs during 2008.

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. Income tax expense was higher in 2009 principally due to a tax benefit that resulted from trading losses incurred by one of our corporate subsidiaries in 2008.

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.

For additional information regarding our business segments, see Item 1 and Notes 1 and 15 to our consolidated financial statements.

Operating income (loss) by segment is as follows:

	Years Ended December 31,		
	2009	2008	Change
Intrastate transportation and storage	$ 626,779	$ 718,348	$ (91,569)
Interstate transportation	138,233	124,676	13,557
Midstream	140,732	166,414	(25,682)
Retail propane and other retail propane related	229,229	114,564	114,665
All other	(8,658)	(1,531)	(7,127)
Unallocated selling, general and and administrative expenses	1,292	(4,892)	6,184
Operating income	$ 1,127,607	$ 1,117,579	$ 10,028

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses are allocated monthly to the Operating Companies 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, which results in over or under allocation of these costs due to timing differences.

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Intrastate Transportation and Storage

	Years Ended December 31,		
	2009	2008	Change
Natural gas MMBtu/d - transported	12,254,168	11,187,327	1,066,841
Natural gas MMBtu/d - sold	969,601	1,389,781	(420,180)
Revenues	$ 2,391,544	$ 5,634,604	$ (3,243,060)
Cost of products sold	1,393,295	4,467,552	(3,074,257)
Gross margin	998,249	1,167,052	(168,803)
Operating expenses	199,806	287,515	(87,709)
Depreciation and amortization	107,605	84,701	22,904
Selling, general and administrative	64,059	76,488	(12,429)
Segment operating income	$ 626,779	$ 718,348	$ (91,569)

Volumes. Overall volumes on our transportation pipelines were higher in 2009, principally due to the increased capacity of our pipeline system as a result of the completion of the Paris Loop, Maypearl to Malone pipeline, Carthage Loop, Southern Shale pipeline, Cleburne to Tolar pipeline, the Katy expansion and the Texas Independence Pipeline during 2008 and 2009. Natural gas sold decreased between the periods principally due to decreased demand from industrial end users and local distribution companies. Natural gas sold also includes net retained fuel, which is the excess of retained fuel less fuel consumed. Our net retained fuel volumes increased as compared to 2008.

Gross Margin. Intrastate transportation and storage gross margin decreased between periods primarily due to the following factors:

We recognized $639.0 million in margin from transportation fees during 2009, an increase of approximately $41.0 million compared to 2008, primarily due to increased volumes through our transportation pipelines from the additional capacity and additional demand fees added as a result of the additional capacity.

We recognized approximately $137.9 million in margin from retained fuel during 2009. Our fuel retention margin is directly impacted by changes in natural gas prices and transported volumes. We experienced an increase in natural gas volumes transported between periods; however, natural gas prices for retained fuel decreased from an average of $7.90/MMBtu during 2008 to $3.54/MMBtu during 2009, resulting in a decrease to the retention margin between the periods of $168.6 million.

We recognized $91.5 million in margin from the sale of natural gas in 2009, which was a reduction of $37.9 million compared to 2008, primarily due to the decrease in natural gas sold as a result of lower natural gas prices, lower price differentials, and lower demand from industrial end users and local distribution companies.

We recognized approximately $129.5 million in net storage margin during 2009, a decrease of $3.7 million from 2008. The activity resulting in the change was as follows:

- We recognized margin of $98.6 million in 2009 from the sale of natural gas from our Bammel storage facility, a decrease of $92.9 million from 2008. During 2008 and 2009, we accounted for certain of our storage-related derivative instruments using mark-to-market accounting with changes in the value of these financial derivative instruments being recorded directly in earnings. During 2009, we recognized unrealized losses of $93.8 million from mark-to-market non-fair value hedge accounting adjustments; we recognized unrealized gains of $89.9 million in 2008. Additionally, we recognized realized gains of $168.8 million and $3.9 million from the settlement of derivative contracts during 2009 and 2008, respectively.

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- Beginning in April 2009, we elected fair value hedge accounting for certain storage-related transactions. We recognized net unrealized gains of $48.6 million as a result of fair value hedge accounting.

- We also recognized $54.0 million and $69.5 million of non-cash lower of cost or market adjustments in 2009 and 2008, respectively.

- We recognized margin of approximately $39.7 million during 2009 from our third-party fee-based storage revenue, an increase of $5.7 million compared to 2008.

Excluding the derivatives relating to storage activities discussed above, we recognized unrealized gains of $20.9 million in 2009 and unrealized losses of $10.1 million in 2008 on financial derivatives to mitigate price risk associated with transportation activities. These amounts are included in the margin from retained fuel and the sale of natural gas discussed above.

Operating Expenses. Intrastate transportation and storage operating expenses decreased between the periods primarily due to a decrease in the cost of natural gas consumed of $93.1 million from $149.0 million in 2008 to $55.9 million in 2009. This decrease was principally due to both a decrease in consumption volumes and a decrease in natural gas prices as compared to the prior year. In addition, we experienced a decrease in electricity costs of approximately $12.9 million between the periods. Offsetting these decreases were increases in ad valorem taxes of $15.3 million, resulting from increased property values and additions, and increases in pipeline maintenance expenses of approximately $3.4 million.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased primarily due to the completion of pipeline expansion projects as noted above.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses decreased between the periods primarily due to decreased employee-related costs (including allocated overhead expenses) of approximately $9.5 million and a decrease in professional fees of approximately $2.8 million.

Interstate Transportation

	Years Ended December 31,		
	2009	2008	Change
Natural gas MMBtu/d - transported	1,661,785	1,777,097	(115,312)
Natural gas MMBtu/d - sold	18,531	15,162	3,369
Revenues	$ 270,213	$ 244,224	$ 25,989
Operating expenses	59,343	56,906	2,437
Depreciation and amortization	48,297	37,790	10,507
Selling, general and administrative	24,340	24,852	(512)
Segment operating income	$ 138,233	$ 124,676	$ 13,557

Interstate transportation segment table does not include the natural gas volumes transported or sold, or the operating income of our interstate pipeline joint ventures, which is reflected below operating income in our consolidated statement of operations. During 2009, we recognized $14.0 million in equity in earnings related to our 50% joint venture investment in MEP.

Volumes. Transported volumes decreased as compared to 2008 primarily as a result of less favorable pricing differentials between the San Juan and Permian Basins during the period.

Revenues. Interstate transportation revenues increased between the periods by approximately $42.5 million primarily as a result of the completion of the Phoenix project in February 2009. This increase was partially offset by a $16.5 million decrease in operational gas sales primarily due to decreased natural gas prices between the periods.

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Operating Expenses. Interstate operating expenses increased between the periods due to an increase in ad valorem taxes of approximately $4.2 million resulting from increased property values related to the Phoenix pipeline expansion. The increase in ad valorem taxes was partially offset by a net decrease of $1.4 million in operating expenses primarily due to lower electric demand costs, professional fees and gas imbalance activities.

Depreciation and Amortization. Interstate depreciation and amortization expense increased by $10.5 million between the periods primarily due to incremental depreciation associated with the completion of the San Juan lateral and Phoenix projects.

Midstream

	Years Ended December 31, 2009	2008	Change
Natural gas MMBtu/d - sold	1,080,552	1,269,724	(189,172)
NGLs Bbls/d - sold	39,064	25,939	13,125
Revenues	$ 2,441,160	$ 5,342,393	$ (2,901,233)
Cost of products sold	2,116,279	4,986,495	(2,870,216)
Gross margin	324,881	355,898	(31,017)
Operating expenses	68,989	82,872	(13,883)
Depreciation and amortization	70,845	59,344	11,501
Selling, general and administrative	44,315	47,268	(2,953)
Segment operating income	$ 140,732	$ 166,414	$ (25,682)

Volumes. The decrease in the volumes of natural gas sold was primarily due to less favorable marketing activities as compared to 2008, and the increase in NGL volumes sold was due to increased capacity to delivery NGL volumes at our Godley plant starting in January 2009.

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

We recognized $141.0 million in processing margin, a decrease of $53.9 million compared to the prior year. The decrease in margin was primarily due to less favorable processing conditions during the period as compared to 2008.

We recognized $170.2 million in gathering, processing and treating fee-based revenues, an increase of $6.4 million compared to the prior year. The increase in fee-based revenue was principally a result of more take away capacity at our Godley plant that allowed for an increase in fee-based processing volumes.

We recognized $13.6 million in margin from our marketing activities during 2009. This was a favorable change between the periods of approximately $16.5 million primarily due to losses recognized from trading activities during 2008. As noted above, we ceased these trading activities in the latter part of 2008.

Included in the marketing activity discussed above are unrealized gains of $8.7 million and $1.3 million in 2009 and 2008, respectively, on financial derivatives related to our midstream activities.

Operating Expenses. Midstream operating expenses decreased between the periods primarily due to a $11.4 million goodwill impairment charge related to our Canyon assets in 2008. Additionally, we experienced a decrease in compressor expense of $1.9 million, a decrease in plant operating expenses of $1.6 million and a net decrease in other operating expenses of $1.8 million. These decreases were offset by an increase in ad valorem taxes of $2.9 million due to increased property values.

Depreciation and Amortization. Midstream depreciation and amortization expense increased between the periods primarily due to incremental depreciation from the continued expansion of our Godley plant.

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Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses decreased between the periods primarily due to a decrease in employee-related costs (including allocated overhead expenses) of approximately $16.8 million. This decrease was partially offset by an increase in professional fees of $3.0 million, $10 million related to the FERC settlement and a net increase of $0.9 million in other general and administrative expenses.

Retail Propane and Other Retail Propane Related

	Years Ended December 31, 2009	2008	Change
Retail propane gallons (in thousands)	568,315	601,134	(32,819)
Retail propane revenues	$ 1,190,523	$ 1,514,599	$ (324,076)
Other retail propane related revenues	102,060	109,411	(7,351)
Retail propane cost of products sold	574,854	1,014,068	(439,214)
Other retail propane related cost of products sold	21,148	24,654	(3,506)
Gross margin	696,581	585,288	111,293
Operating expenses	341,935	350,280	(8,345)
Depreciation and amortization	83,476	79,717	3,759
Selling, general and administrative	41,941	40,727	1,214
Segment operating income	$ 229,229	$ 114,564	$ 114,665

Volumes. Retail propane volumes decreased primarily due to the continued effects of customer conservation, the impact of the economic recession, and to a lesser extent, the decline in new home construction. These decreases were partially offset by volume increases from acquisitions that were made after January 1, 2008 and therefore were not included in the results for the full year ended December 31, 2008. We use information on temperatures based on heating degree days published by the National Oceanic and Atmospheric Administration (NOAA) to analyze how our volume sales are affected by temperature. Our normal temperatures are based on the average heating degree days provided by NOAA for various data points in our operating areas for the 10-year period ending December 2009. Based on this information, we calculate a ratio of actual heating degree days to normal heating degree days. Temperatures during the year ended December 31, 2009 were 4.1% colder than normal and were just slightly colder than the year ended December 31, 2008.

Gross Margin. Total gross margin increased $111.3 million or 19.0% for the year ended December 31, 2009 compared to the year ended December 31, 2008. This increase was principally due to the benefit of the rapid decline in commodity prices in the first half of 2009 compared to the historically high commodity prices reached in 2008, which resulted in a reduction in product costs that outpaced the decline in average selling prices and the impact of mark-to-market accounting of our financial instruments. The average sales price per retail gallon sold decreased approximately 17.0% for the year ended December 31, 2009 compared to the year ended December 31, 2008 while the average cost per gallon of propane was approximately 35.0% lower during the year ended December 31, 2009 as compared to the year ended December 31, 2008. To hedge a significant portion of our propane sales commitments entered into under our customer prebuy programs, we utilize financial instruments to lock in margins. Prior to April 2009, these financial instruments were not designated as cash flow hedges for accounting purposes, and changes in market value were recorded in cost of products sold in the consolidated statements of operations. During 2009, our propane margins were positively impacted by the settlement of financial instruments related to sales commitments that were entered into in 2008. We recognized unrealized losses of $45.6 million on these financial instruments in 2008 and we recognized unrealized gains of $45.6 million when they settled in 2009.

Operating Expenses. The decrease in operating expenses was principally due to a decrease of $9.7 million in vehicle fuel used for delivery to customers due to the significant decline in fuel prices between the periods, a

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decrease of $4.0 million in bad debt expense due to improved collections in the accounts receivable in 2009, which also lead to a reduction in our reserve for bad debts, and a decrease of $2.9 million related to cost control initiatives from our operations. These decreases were offset by an increase in payroll costs of $3.9 million due to an increase related to additional employees from acquisitions in the latter part of 2008, merit increases, and an increase in medical expenses of $4.2 million. Our business insurance reserves and claims also increased by $5.2 million.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense was primarily related to assets added through acquisitions in the latter part of 2008.

Selling, General and Administrative. The increase in selling, general and administrative expenses between comparable periods was primarily due to increased administrative expense allocations of $1.5 million offset by a reduction in other non-recurring expenses incurred during the prior periods.

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

Consolidated Results

	Years Ended December 31, 2008	Years Ended August 31, 2007	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)
Losses 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
Net income	$ 866,023	$ 677,281	$ 188,742

See the detailed discussion of revenues, costs of products sold, gross margin, operating expenses, and depreciation and amortization 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 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 increases in the 10 year LIBOR rate during the period.

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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 related to $40.0 million reimbursement in connection with an extension on our Southeast Bossier pipeline (see Note 2 to our consolidated financial statements).

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

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

Segment Operating Results

Operating income by segment is as follows:

	Years Ended December 31, 2008	Years Ended August 31, 2007	Change
Intrastate transportation and storage	$ 718,348	$ 488,098	$ 230,250
Interstate transportation	124,676	95,650	29,026
Midstream	166,414	123,176	43,238
Retail propane and other retail propane related	114,564	124,263	(9,699)
All other	(1,531)	1,735	(3,266)
Unallocated selling, general and and administrative expenses	(4,892)	(3,270)	(1,622)
Operating income	$ 1,117,579	$ 829,652	$ 287,927

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 Companies using the 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.

Intrastate Transportation and Storage

	Years Ended December 31, 2008	Years Ended August 31, 2007	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

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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. This was 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 $89.9 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.

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

	Years Ended December 31, 2008	Years Ended August 31, 2007	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

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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.

Midstream

	Years Ended December 31, 2008	Years Ended August 31, 2007	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 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.

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.

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Retail Propane and Other Retail Propane Related

	Years Ended December 31, 2008	Years Ended August 31, 2007	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.

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. 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. 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. Fuel prices significantly declined during the last three months of the year ended December 31, 2008, but the overall price per gallon for the year ended December 31, 2008 was 38.8% higher than the year ended August 31, 2007. In addition, we entered into propane sales commitments with a portion of our retail customers that provide for a contracted price agreement for a specified period of time, typically no longer than one year. These commitments can expose the operations to product price risk if not offset by a propane purchase commitment. To hedge a significant portion of these sales commitments, we utilize financial instruments to lock in 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.

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

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

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

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

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

Consolidated Results

	Four Months Ended December 31,		
	2007	2006	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)
Gains 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)
Net income	$ 261,824	$ 160,935	$ 100,889

See the detailed discussion of revenues, costs of products sold, gross margin, operating expenses, and depreciation and amortization 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 (expense), net for the four months ended December 31, 2007. The increase in interest expense was also offset by propane related interest, which decreased $2.0 million due primarily to the scheduled debt payments that have occurred between the four-month periods.

Equity in Earnings of Affiliates. The decrease in equity in earnings (losses) of affiliates was due primarily to $5.1 million of equity income from our 50% ownership of the member interests in CCE Holdings, LLC

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(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.

Gains 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.

Segment Operating Results

Operating income by segment is as follows:

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

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 Companies using the 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 Companies exceeded total incurred costs.

Intrastate Transportation and Storage

	Four Months Ended December 31,		
	2007	2006	Change
Natural gas MMBtu/d - transported	8,787,387	4,889,029	3,898,358
Natural gas MMBtu/d - sold	1,259,566	1,379,721	(120,155)
Revenues	$ 1,254,401	$ 1,195,871	$ 58,530
Cost of products sold	964,568	994,511	(29,943)
Gross margin	289,833	201,360	88,473

Operating expenses	76,428	56,452	19,976
Depreciation and amortization	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

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

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

Natural gas sales volumes on the HPL System decreased primarily due to the new CenterPoint contract that commenced on April 1, 2007. Under the previous contract, we sold and delivered natural gas to CenterPoint for a bundled price. Under the terms of the new agreement, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas capacity in our Bammel storage facility.

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

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

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

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

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

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

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Interstate Transportation

	Four Months Ended December 31, 2007	2006	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.

Midstream

	Four Months Ended December 31, 2007	2006	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;

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.

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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.

Retail Propane and Other Retail Propane Related

	Four Months Ended December 31,		
	2007	2006	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.

Gross Margin. Overall gross margins increased $3.6 million even though gallon sales decreased. Retail propane revenues increased mainly due to increased sale prices driven by 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. Retail propane cost of products sold increased 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. 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.

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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 companies, 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 companies.

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.

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 midstream and intrastate transportation and storage segments primarily for the construction of new pipelines and compression, for which we expect to spend between $200 million and $230 million in 2010;

- growth capital expenditures for our interstate transportation segment, excluding capital contributions to our joint ventures as discussed below, for the construction of new pipelines for which we expect to spend between $1.01 billion and $1.06 billion in 2010;

- growth capital expenditures for our retail propane segment of between $30 million and $40 million in 2010; and

- maintenance capital expenditures of between $110 million and $120 million during 2010, 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.

In addition to the capital expenditures noted above, we expect to make capital contributions to our joint ventures of between $90 million and $105 million in 2010. In November 2009, FEP entered into a $1.1 billion credit facility, which will be used to fund FEP s capital expenditures. Therefore, we do not expect to make any capital contributions to FEP in 2010.

In addition, we may enter into acquisitions, including the potential acquisition of new pipeline systems and propane operations.

We generally fund our capital requirements 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.

During the year ended December 31, 2009, we raised approximately $853.7 million in net proceeds from our January, April and October Common Unit offerings, $993.6 million in net proceeds from an offering of $1.0 billion aggregate principal amount of senior notes in April, and $348.4 million in net proceeds from an offering of $350.0 million aggregate principal amount of senior notes at Transwestern in December 2009. In addition, we raised $81.5 million in net proceeds during November and December 2009 under an equity distribution program, as described in Note 7 to our consolidated financial statements. As of December 31, 2009, in addition to approximately $68.2 million of cash on hand, we had available capacity under the ETP Credit Facility of

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approximately $1.79 billion. In addition, we received approximately $423.6 million of net proceeds from our Common Unit offering in January 2010. Based on our current estimates, we expect to utilize these resources, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2010; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects or other partnership purposes.

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. 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.

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

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in Results of Operations above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash executive compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense result from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period.

Year Ended December 31, 2009

Cash provided by operating activities during 2009 was $826.9 million and net income was $791.5 million. The difference between net income and cash provided by operations during 2009 consisted of non-cash items totaling $359.3 million (principally depreciation and amortization expense of $312.8 million and non-cash compensation expense of $25.3 million, offset by net changes in operating assets and liabilities of $324.0 million.

Year Ended December 31, 2008

Cash provided by operating activities during 2008 was $1.26 billion. Net income was $866.0 million. The difference between net income and the net cash provided by operations for 2008 consisted of non-cash items totaling $317.2 million (principally depreciation and amortization expense of $262.2 million) and changes in operating assets and liabilities of $75.0 million.

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Four Months Ended December 31, 2007

Cash provided by operating activities during the four months ended December 31, 2007 was $245.7 million. The net cash provided by operations for the four months ended December 31, 2007 consisted of net income of $261.8 million and non-cash items totaling $70.9 million (principally depreciation and amortization expense of $71.3 million and non-cash compensation expense of $8.6 million, partially offset by gains on disposal of assets of $14.3 million), offset by changes in operating assets and liabilities of $87.1 million.

Year Ended August 31, 2007

Cash provided by operating activities during the year ended August 31, 2007 was $1.11 billion. The net cash provided by operations for the year ended August 31, 2007 consisted of net income of $677.3 million, non-cash items totaling $194.3 million (principally depreciation and amortization expense of $179.2 million, non-cash compensation expense of $10.5 million) and changes in operating assets and liabilities of $241.2 million.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, and cash contributions to our joint ventures. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Following is a summary of investing activities by period.

Year Ended December 31, 2009

Cash used in investing activities during 2009 of $1.35 billion was comprised primarily of $530.3 million invested for growth capital expenditures (excluding the allowance for equity funds used during construction), including changes in accruals of $115.7 million. Total growth capital expenditures consist of $412.0 million for our midstream and intrastate operations, $78.9 million for our interstate operations, and $39.5 million for our propane operations. We also incurred $102.7 million in maintenance expenditures needed to sustain operations of which $65.0 million related to midstream and intrastate operations, $13.2 million related to interstate operations, and $24.4 million to propane operations. In addition, we made advances to MEP of $664.5 million and received a reimbursement from FEP of all of our contributions, including $9.0 million that we contributed in 2008. As a result of our acquisition of a natural gas compression equipment business in exchange for ETP Common Units, cash acquired in connection with acquisitions during 2009 exceeded the cash we paid by $30.4 million.

Year Ended December 31, 2008

Cash used in investing activities during 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 2008.

Four Months Ended December 31, 2007

Cash used in investing activities during the four months ended December 31, 2007 of $995.9 million was comprised primarily of cash paid for acquisitions of $337.1 million and $607.7 million invested for growth capital expenditures, including changes in accruals of $5.6 million. Total growth capital expenditures consist of $426.2 million for our intrastate operations and $167.1 million for our interstate operations, and $14.3 million for our propane operations. We also incurred $49.0 million in maintenance expenditures needed to sustain operations of which $21.4 million related to intrastate operations, $12.9 million related to interstate operations, and $14.7 million to propane operations.

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Year Ended August 31, 2007

Cash used in investing activities during the year ended August 31, 2007 of $2.16 billion is comprised primarily of cash paid for our investment in CCEH of $1.00 billion (net of the receipt of $49.0 million from CCEH as per the terms of our acquisition agreement), other acquisitions of $90.7 million and $1.02 billion invested for growth capital expenditures (including the payment of $9.4 million accrued in prior periods) of which $985.1 million related to natural gas operations and $32.9 million to propane operations. We also incurred $89.2 million in maintenance expenditures needed to sustain operations of which $63.2 million related to natural gas operations and $26.0 million to propane.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, as discussed below under Financing and Sources of Liquidity, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increase between the periods based on increases in the number of Common Units outstanding and, for periods prior to 2009, also reflect increases in the declared quarterly distribution per unit, as discussed below under Cash Distributions.

Following is a summary of financing activities by period.

Year Ended December 31, 2009

Cash provided by financing activities was $495.2 million for 2009. We received $936.3 million in net proceeds from Common Unit offerings, including $81.5 million under an equity distribution program (see Note 7 to our consolidated financial statements). Net proceeds from the offerings were used to repay borrowings under the ETP Credit Facility, to fund capital expenditures and capital contributions to joint ventures. During 2009, we had a net increase in our debt level of $520.4 million primarily due to borrowings to fund capital expenditures and to fund capital contributions to joint ventures, partially offset by the use of proceeds from our Common Unit offerings. We issued Senior Notes (see Note 6 to our consolidated financial statements) for net proceeds of $993.6 million, which were used to repay outstanding borrowings under the ETP Credit Facility and for general partnership purposes. In addition, in December 2009, Transwestern issued $350.0 million aggregate principal amount of senior notes, the proceeds from which were used to repay a portion of Transwestern s intercompany indebtedness to ETP. The Partnership, in turn, used the proceeds from Transwestern s intercompany loan repayment to repay outstanding borrowings under the ETP Credit Facility. During 2009, we paid distributions of $957.3 million to our partners.

Year Ended December 31, 2008

Cash provided by financing activities was $792.9 million for 2008. We received $373.1 million in net proceeds from equity offerings. 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, which were used to repay other indebtedness. During 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 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.

Four Months Ended December 31, 2007

Cash provided by financing activities was $738.0 million for the four months ended December 31, 2007. We received $234.9 million in net proceeds from an equity offering. Proceeds from the equity offering and funds from the ETP Credit Facility were used to repay the debt related to the Canyon acquisition. We had a net increase in our debt level of $666.4 million primarily under the ETP Credit Facility to partially repay the ETP Term Loan Facility, to fund our growth capital expenditures and for general partnership purposes. During the four months ended December 31, 2007, we paid distributions of $176.0 million to our partners related to the fourth quarter of our fiscal year 2007.

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Year Ended August 31, 2007

Cash provided by financing activities was $1.09 billion for the year ended August 31, 2007. We received $1.2 billion in proceeds from the sale of Class G Units to ETE and our General Partner contributed $24.5 million to maintain its ownership in us. We used $1.00 billion of the proceeds to fund the purchase of the member interests of CCEH and the remainder was used to repay the indebtedness we incurred in connection with the Titan acquisition. During the year ended August 31, 2007, we received net proceeds of $791.0 million from the issuance of senior notes, which we used to repay borrowings under the Partnership s revolving credit facility. In addition, we borrowed a total of approximately $307.0 million on our Revolving Credit Facility to fund required pre-payments of the debt we assumed in connection with our acquisition of Transwestern. Transwestern issued $307.0 million principal of Senior Unsecured Series Notes. We used the proceeds to repay borrowings and accrued interest outstanding under the Partnership s revolving credit facility and for general partnership purposes. During the year ended August 31, 2007, we paid distributions of $622.5 million to our partners.

Financing and Sources of Liquidity

The following table summarizes our public offerings of Common Units since December 2007, all of which have been registered under the Securities Act of 1933, as amended:

Date	Number of Common Units (1)	Price per Unit	Net Proceeds	Use of Proceeds
December 2007 (2)	5,750,000	$ 48.81	$ 269.4	(3)
July 2008	8,912,500	39.45	337.5	(4)
January 2009	6,900,000	34.05	225.4	(4)
April 2009	9,775,000	37.55	352.4	(5)
October 2009	6,900,000	41.27	276.0	(4)
January 2010	9,775,000	44.72	423.6	(4)(5)

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.
(2) Amounts include the exercise of the overallotment option by the underwriters in January 2008.
(3) Proceeds were used to repay amounts outstanding under ETP s prior term loan facility.
(4) Proceeds were used to repay amounts outstanding under the ETP Credit Facility.
(5) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC (UBS). According to the provisions of this agreement, we may offer and sell from time to time through UBS, as our sales agent, common units having an aggregate offering price of up to $300.0 million. Sales of the units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During 2009, we issued 1,891,691 of our Common Units pursuant to this agreement. The net proceeds of approximately $81.5 million were used to repay amounts outstanding under our revolving credit facility.

In April 2009, we completed a public offering of $350.0 million aggregate principal amount of our 8.5% Senior Notes due 2014 and $650.0 million aggregate principal amount of our 9.0% Senior Notes due 2019 (collectively the 2009 ETP Notes). We used the net proceeds of approximately $993.6 million from the offering to repay all borrowings outstanding under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

In December 2009, Transwestern completed a private placement offering of $175.0 million of 5.36% Senior Unsecured Series A Notes due 2020 and $175.0 million of 5.66% Senior Unsecured Series B Notes due 2024.

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Transwestern used the proceeds from these notes to repay a portion of its intercompany indebtedness to the Partnership, and the Partnership, in turn, used the proceeds from Transwestern s intercompany loan repayment to repay outstanding borrowings under the ETP Credit Facility.

Description of Indebtedness

Our outstanding indebtedness was as follows:

	December 31, 2009	December 31, 2008
ETP Senior Notes	$ 5,050,000	$ 4,050,000
Transwestern Senior Unsecured Notes	870,000	520,000
HOLP Senior Secured Notes	140,512	181,410
Revolving Credit Facilities	160,000	912,000
Other long-term debt	10,122	13,814
Unamortized discounts	(12,829)	(13,477)
Total Debt	$ 6,217,805	$ 5,663,747

The terms of our indebtedness and that of our Operating Companies are described in more detail below and in Note 6 to our consolidated financial statements. Failure to comply with the various restrictive covenants of the debt 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 access compliance quarterly and, as of December 31, 2009, we were in compliance with all financial requirements, limitations, and covenants related to financial ratios under our existing debt agreements. See Debt Covenants below.

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). 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 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; the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of December 31, 2009, there was a balance of $150.0 million outstanding on the ETP Credit Facility and taking into account letters of credit of approximately $62.2 million, $1.79 billion was available for future borrowings. The weighted average interest rate on the total amount outstanding at December 31, 2009 was 0.78%.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available through June 30, 2011, which may be expanded to $150.0 million. 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 in the credit agreement for the HOLP Credit Facility, 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,

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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, 2009 of approximately $1.2 billion). At December 31, 2009, there was $10.0 million outstanding in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of December 31, 2009 was $64.0 million.

Other

MEP Facility

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (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 commitment amount under the MEP Facility was originally $1.4 billion. In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by us or KMP. In October 2009, the members made additional capital contributions to MEP, which MEP used to further reduce the outstanding borrowings under the MEP Facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275.0 million.

As of December 31, 2009, MEP had $29.5 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 $14.7 million and $16.6 million, respectively, as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.3%.

FEP Facility

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the FEP Facility). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP 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 FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of December 31, 2009, FEP had $355.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP s outstanding borrowings was $177.5 million as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.2%.

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 Companies, 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.

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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 hedging contracts for purposes of speculation.

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. This financial covenant could therefore restrict our ability to make cash distributions to our Unitholders, our general partner and the holder of our incentive distribution rights.

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 revolving 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 Companies ability to incur additional debt and/or our ability to pay distributions.

We are required to assess compliance quarterly and were in compliance with all requirements, limitations, and covenants related to the Partnership s, Transwestern s and HOLP s debt agreements as of December 31, 2009. We plan to fund our working capital needs and growth capital expenditures, including the Tiger pipeline

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(expected completion in early 2011), with cash on hand, cash flow from operations, and borrowings under the ETP Credit Facility. However, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects or other partnership purposes. 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 2010 will allow us to satisfy the financial ratio covenants related to our existing debt during 2010.

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.

Off Balance Sheet Arrangements

Our MEP and FEP joint ventures are not consolidated in our financial statements. As described above under Financing and Sources of Liquidity Revolving Credit Facilities Other, we have guaranteed 50% of the obligations of both MEP and FEP under their senior revolving credit facilities, with the remaining 50% of the obligations guaranteed by KMP. As of December 31, 2009, our contingent obligations with respect to our 50% guarantee of our joint ventures outstanding borrowings and letters of credit totaled $192.2 million and $16.6 million, respectively.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2009 (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	$ 6,217,805	$ 40,887	$ 617,405	$ 816,042	$ 4,743,471
Interest on long-term debt (a)	4,735,003	429,141	848,505	757,408	2,699,949
Payments on derivatives	442	442	-	-	-
Purchase commitments (b)	1,048,642	468,612	273,015	272,902	34,113
Operating lease obligations	326,904	27,216	47,308	38,292	214,088
Totals	$ 12,328,796	$ 966,298	$ 1,786,233	$ 1,884,644	$ 7,691,621

(a) Interest payments on long-term debt are based on the principal amount of debt obligations at December 31, 2009. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2009. At December 31, 2009, we had $160.0 million of variable rate debt outstanding, for which a hypothetical change of 100 basis points in the underlying interest rates would result in a net change in interest expense of approximately $1.6 million on an annual basis. See Note 6 Debt Obligations to the consolidated financial statements in Item 8 of this report for further discussion of the long-term debt classifications and the maturity dates and interest rates related to long-term debt.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for propane and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the December 31, 2009 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 expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies 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, 2009	November 9, 2009	November 16, 2009	$ 0.89375
	August 7, 2009	August 14, 2009	0.89375
	May 8, 2009	May 15, 2009	0.89375
	February 6, 2009	February 13, 2009	0.89375
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

(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. The 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.

On January 28, 2010, we declared a cash distribution for the fourth quarter ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized. We paid this distribution on February 15, 2010 to Unitholders of record at the close of business on February 8, 2010.

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The total amount of distributions declared during the periods (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate) are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 629,263	$ 537,731	$ 160,672	$ 396,095
Class E Units (1)	12,484	12,484	3,121	12,484
Class G Units (2)	-	-	-	40,598
General Partner interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$ 1,011,738	$ 866,112	$ 254,678	$ 685,235

(1) See Note 7 of our consolidated financial statements for more information on the Class E Units.

(2) Class G Units, which were issued to ETE in November 2006, subsequently converted to Common Units in May 2007. Upon their conversion to Common Units, the Class G Units ceased to have the right to participate in distributions of available cash from operating surplus.

New Accounting Standards

See Note 2 to our consolidated financial statements.

Estimates and Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules are critical. Our critical accounting policies are discussed below. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 2 to our consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and accruals for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the year ended December 31, 2009 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.

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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. Revenues from service labor, transportation, treating, compression and gas processing, are 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.

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.

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 activities 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

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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 oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Revenue and costs related to energy trading contracts considered trading activities for accounting purposes are presented on a net basis in our statement of operations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, 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 senior management and predefined limits and authorizations set forth in our risk management policy.

We utilize our excess storage capacity to inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

Regulatory Assets and Liabilities. Our interstate transportation segment is subject to regulation by certain state and federal authorities and has accounting policies that conform to 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.

Accounting for Derivative Instruments and Hedging Activities. 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 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

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marketing product costs in the consolidated statement of operations. The 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, the effective portion of the hedged gain or loss is initially reported as a component of other comprehensive income and is subsequently reclassified into earnings when the physical transaction settles. The ineffective portion of the gain or loss is reported in earnings immediately. If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

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.

Fair Value of 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. We determine the fair value of our financial assets and liabilities subject to fair value measurement by using the highest possible level of inputs. 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 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 that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations. 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. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

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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 when incurred. Upon disposition or retirement of pipeline components or gas plant components, any gain or loss is recorded in 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 83 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful lives of our property, plant and equipment.

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

In order to determine fair value, management must make certain estimates and assumptions including, among other things, projected cash flows, a credit-adjusted risk-free rate and an assessment of market conditions that could significantly impact the estimated fair value of the asset retirement obligation. These estimates and assumptions are very subjective.

We have determined that we are obligated by contractual or regulatory requirements to remove assets or perform other remediation upon retirement of certain assets. However, the fair value of our asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. We will record an asset retirement obligation in the periods in which we can reasonably determine the settlement dates.

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

For more information on our litigation and contingencies, see Note 11 to our consolidated financial statements included in Item 8 in this report.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as anticipate, project, expect, plan, goal, forecast, 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

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uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the amount of natural gas transported on our pipelines and gathering systems;
- the level of throughput in our natural gas processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and natural gas liquids, or NGLs;
- energy prices generally;
- the prices of natural gas and propane compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of propane supplies;
- the level of domestic oil, propane and natural gas production;
- the availability of imported oil and natural gas;
- the ability to obtain adequate supplies of propane for retail sale in the event of an interruption in supply or transportation and the availability of capacity to transport propane to market areas;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and propane;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;

availability and marketing of competitive fuels;

the impact of energy conservation efforts;

energy efficiencies and technological trends;

governmental regulation and taxation;

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

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

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

competition from other midstream companies, interstate pipeline companies and propane distribution companies;

loss of key personnel;

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

reductions in the capacity or allocations of third party pipelines that connect with our pipelines and facilities;

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

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- 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. As of July 2008, we no longer engage in trading activities; therefore, all of our derivative instruments now represent non-trading activities, which are substantially offset by physical or other financial positions.

Commodity Price Risk

For certain of our activities, we are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and over-the-counter (OTC) commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention gas, a portion of volumes purchased at the wellhead from producers, and location price differentials related to the transportation of natural gas.

Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.

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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.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in accumulated other comprehensive income (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 earnings. 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 do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. Changes in the spreads between the forward natural gas prices designated as fair value hedges and the physical Bammel inventory spot price result in unrealized margins until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized.

We attempt to maintain balanced positions in our marketing 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 most of 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 position and results of operations, either favorably or unfavorably.

The table below summarizes our commodity-related financial derivative instruments and fair values as of December 31, 2009 and 2008, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas and gallons for propane/ethane.

	December 31,					
	2009			2008		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark to Market Derivatives						
Basis Swaps IFERC/NYMEX - Natural Gas	72,325,000	$ 24,554	$ 491	15,720,000	$ 3,125	$ 865
Swing Swaps IFERC - Natural Gas	(38,935,000)	1,718	2,142	(58,045,000)	(118)	1
Fixed Swaps/Futures - Natural Gas	4,852,500	9,949	3,126	(20,880,000)	97,498	11,824
Options Puts - Natural Gas	2,640,000	837	447	-	-	-
Options Calls - Natural Gas	(2,640,000)	(819)	314	-	-	-
Forwards/Swaps - Propane/Ethane	6,090,000	3,348	785	47,313,002	(42,288)	3,074
Fair Value Hedging Derivatives						
Basis Swaps IFERC/NYMEX - Natural Gas	(22,625,000)	$ (4,178)	$ 2	-	$ -	$ -
Fixed Swaps/Futures - Natural Gas	(27,300,000)	(13,285)	15,669	-	-	-
Cash Flow Hedging Derivatives						
Basis Swaps IFERC/NYMEX - Natural Gas	(13,225,000)	$ (1,640)	$ 81	(9,085,000)	$ 3,268	$ 837
Fixed Swaps/Futures - Natural Gas	(22,800,000)	(4,464)	13,197	(9,085,000)	6,691	5,577
Forwards/Swaps - Propane/Ethane	20,538,000	8,443	2,609	-	-	-

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During the second half of 2009, we began entering into hedges to lock in prices on a portion of our estimated volumes exposed to natural gas price risk. The resulting increase in our short natural gas derivative position is reflected in the December 31, 2009 fixed swap amounts above.

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 other comprehensive income. 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 instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

We are exposed to market risk for increases in interest rates, primarily as a result of our revolving credit facilities, which have variable interest rates. To the extent interest rates increase, our interest expense under these revolving credit facilities will increase. At December 31, 2009, we had $160.0 million of variable rate debt outstanding, for which a hypothetical change of 100 basis points in the underlying interest rates would result in a net change in interest expense of approximately $1.6 million on an annual basis. As of December 31, 2009, we did not have any interest rate swaps outstanding.

In January 2010, we entered into interest rate swaps with notional amounts of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate that mature in July 2013 and February 2015, respectively. These swaps hedge against changes in the fair value of our fixed rate debt.

For further information, see Note 6 to our consolidated financial statements.

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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Energy Transfer Partners, L.P. and Subsidiaries

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Report of Independent Registered Public Accounting Firm

Partners

Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year 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, 2009 and 2008, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Partnership retrospectively adopted a new accounting pronouncement on January 1, 2009 related to the calculation of earnings per unit.

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, 2009, 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 24, 2010 expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 24, 2010

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 68,183	$ 91,902
Marketable securities	6,055	5,915
Accounts receivable, net of allowance for doubtful accounts	566,522	591,257
Accounts receivable from related companies	57,369	17,895
Inventories	389,954	272,348
Exchanges receivable	23,136	45,209
Price risk management assets	12,371	5,423
Other current assets	148,373	153,452
Total current assets	1,271,963	1,183,401
PROPERTY, PLANT AND EQUIPMENT, net	8,670,247	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	663,298	10,110
GOODWILL	745,505	743,694
INTANGIBLES AND OTHER ASSETS, net	383,959	394,199
Total assets	$ 11,734,972	$ 10,627,489

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 358,997	$ 381,135
Accounts payable to related companies	38,842	34,547
Exchanges payable	19,203	54,636
Price risk management liabilities	442	94,978
Interest payable	136,222	106,259
Accrued and other current liabilities	228,946	433,794
Current maturities of long-term debt	40,887	45,198
Total current liabilities	823,539	1,150,547
LONG-TERM DEBT, less current maturities	6,176,918	5,618,549
DEFERRED INCOME TAXES	112,997	100,597
OTHER NON-CURRENT LIABILITIES	21,810	14,727
COMMITMENTS AND CONTINGENCIES (Note 10)		
	7,135,264	6,884,420
PARTNERS CAPITAL:		
General Partner	174,884	161,159
Limited Partners:		
Common Unitholders (179,274,747 and 152,102,471 units authorized, issued and outstanding at December 31, 2009 and 2008, respectively)	4,418,017	3,578,997
Class E Unitholders (8,853,832 units authorized, issued and outstanding - held by subsidiary and reported as treasury units)	-	-
Accumulated other comprehensive income	6,807	2,913
Total partners capital	4,599,708	3,743,069
Total liabilities and partners capital	$ 11,734,972	$ 10,627,489

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

	Years Ended December 31, 2009	2008 As Adjusted (Note 2)	Four Months Ended December 31, 2007 As Adjusted (Note 2)	Year Ended August 31, 2007 As Adjusted (Note 2)
REVENUES:				
Natural gas operations	$ 4,115,806	$ 7,653,156	$ 1,832,192	$ 5,385,892
Retail propane	1,190,524	1,514,599	471,494	1,179,073
Other	110,965	126,113	45,824	227,072
Total revenues	5,417,295	9,293,868	2,349,510	6,792,037
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	2,519,575	5,885,982	1,343,237	4,207,700
Cost of products sold - retail propane	574,854	1,014,068	315,698	734,204
Cost of products sold - other	27,627	38,030	14,719	136,302
Operating expenses	680,893	781,831	221,757	559,600
Depreciation and amortization	312,803	262,151	71,333	179,162
Selling, general and administrative	173,936	194,227	59,132	145,417
Total costs and expenses	4,289,688	8,176,289	2,025,876	5,962,385
OPERATING INCOME	1,127,607	1,117,579	323,634	829,652
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(394,274)	(265,701)	(66,298)	(175,563)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	(1,013)	31,032
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	2,157	9,306	(5,202)	2,019
INCOME BEFORE INCOME TAX EXPENSE	804,319	872,703	272,613	690,939
Income tax expense	12,777	6,680	10,789	13,658
NET INCOME	791,542	866,023	261,824	677,281
LESS: NET INCOME ATTRIBUTABLE TO	-	-	-	1,142

NONCONTROLLING INTEREST								
NET INCOME ATTRIBUTABLE TO PARTNERS		791,542		866,023		261,824		676,139
GENERAL PARTNER S INTEREST IN NET INCOME		365,362		315,896		91,011		235,876
LIMITED PARTNERS INTEREST IN NET INCOME	$	426,180	$	550,127	$	170,813	$	440,263
BASIC NET INCOME PER LIMITED PARTNER UNIT	$	2.53	$	3.74	$	1.24	$	3.32
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING		167,337,192		146,871,261		137,624,934		132,618,053
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$	2.53	$	3.74	$	1.24	$	3.31
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING		167,768,981		147,090,608		138,013,366		132,877,152

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income	$ 791,542	$ 866,023	$ 261,824	$ 677,281
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(10,211)	(34,901)	(17,269)	(160,420)
Change in value of derivative instruments accounted for as cash flow hedges	3,182	17,326	21,626	175,720
Change in value of available-for-sale securities	10,923	(6,418)	(98)	280
	3,894	(23,993)	4,259	15,580
Comprehensive income	795,436	842,030	266,083	692,861
Less: Comprehensive income attributable to noncontrolling interest	-	-	-	1,142
Comprehensive income attributable to partners	$ 795,436	$ 842,030	$ 266,083	$ 691,719

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(Dollars in thousands)

	General Partner	Limited Partners Common Unitholders	Limited Partners Class G Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, August 31, 2006	$ 82,450	$ 1,647,345	$ -	$ 7,067	$ 1,857	$ 1,738,719
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
Other	-	-	-	-	(760)	(760)
Net income	235,876	391,271	48,992	-	1,142	677,281
Balance, August 31, 2007	127,046	2,890,140	-	22,647	2,239	3,042,072
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
Sale of noncontrolling interest and other	-	-	-	-	(2,239)	(2,239)
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, 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
Distributions to partners	(355,016)	(602,239)	-	-	-	(957,255)
Issuance of units in acquisitions	-	63,339	-	-	-	63,339
Issuance of units in public offerings	-	936,337	-	-	-	936,337
Capital contributions from General Partner	12,286	-	-	-	-	12,286
Contributions receivable from General Partner	(8,932)	-	-	-	-	(8,932)
Distributions on unvested unit awards	-	(2,673)	-	-	-	(2,673)
Tax effect of remedial income allocation					-	
from tax amortization of goodwill	-	(3,762)	-	-	-	(3,762)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	-	20,613	-	-	-	20,613
Non-cash executive compensation	25	1,225	-	-	-	1,250
Other comprehensive income loss, net of tax	-	-	-	3,894	-	3,894
Net income	365,362	426,180	-	-	-	791,542
Balance, December 31, 2009	$ 174,884	$ 4,418,017	$ -	$ 6,807	$ -	$ 4,599,708

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 791,542	$ 866,023	$ 261,824	$ 677,281
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	312,803	262,151	71,333	179,162
Amortization of finance costs charged to interest	8,645	5,886	1,435	4,061
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Goodwill impairment	-	11,359	-	-
Non-cash unit-based compensation expense	24,032	23,481	8,114	10,471
Non-cash executive compensation expense	1,250	1,250	442	-
Deferred income taxes	11,966	(5,280)	1,003	(4,042)
(Gains) losses on disposal of assets	1,564	1,303	(14,310)	6,310
Distributions on unvested awards	(2,673)	-	-	-
Distributions in excess of (less than) equity in earnings of affiliates, net	3,224	5,621	4,448	(5,161)
Other non-cash	(4,468)	3,382	(2,069)	(761)
Net change in operating assets and liabilities, net of effects of acquisitions	(323,999)	74,954	(87,062)	241,182
Net cash provided by operating activities	826,878	1,258,145	245,702	1,112,732
CASH FLOWS FROM INVESTING ACTIVITIES:				
Net cash (paid for) received in acquisitions	30,367	(84,783)	(337,092)	(90,695)
Capital expenditures	(748,621)	(2,054,806)	(651,228)	(1,107,127)
Contributions in aid of construction costs	6,453	50,050	3,493	10,463
(Advances to) repayments from affiliates, net	(655,500)	54,534	(32,594)	(993,866)
Proceeds from the sale of assets	21,545	19,420	21,478	23,135
Net cash used in investing activities	(1,345,756)	(2,015,585)	(995,943)	(2,158,090)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	3,475,107	6,015,461	1,741,547	4,757,971
Principal payments on debt	(2,954,737)	(4,699,123)	(1,062,272)	(4,260,494)
Net proceeds from issuance of Limited Partner Units	936,337	373,059	234,887	1,200,000

Capital contribution from General Partner	3,354	7,968	29	24,490
Distributions to partners	(957,255)	(879,218)	(175,977)	(622,548)
Debt issuance costs	(7,647)	(25,272)	(211)	(11,397)
Net cash provided by financing activities	495,159	792,875	738,003	1,088,022
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(23,719)	35,435	(12,238)	42,664
CASH AND CASH EQUIVALENTS, beginning of period	91,902	56,467	68,705	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 68,183	$ 91,902	$ 56,467	$ 68,705

The accompanying notes are an integral part of these consolidated 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 years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, 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 equity and net income attributable to noncontrolling interest for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through February 24, 2010, the date the financial statements were issued.

We are managed by our general partner, Energy Transfer Partners GP, L.P. (our General Partner or ETP GP), which is in turn managed by its general partner, Energy Transfer Partners, L.L.C. (ETP LLC). Energy Transfer Equity, L.P., a publicly traded master limited partnership (ETE), owns ETP LLC, the general partner of our General Partner.

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); ETC Fayetteville Express Pipeline, LLC (ETC FEP); ETC Tiger Pipeline, LLC (ETC Tiger); Heritage Operating, L.P. (HOLP); Heritage Holdings, Inc. (HHI); and Titan Energy Partners, L.P. (Titan). The operations of ET Interstate are included since the date of the Transwestern acquisition on December 1, 2006. ETC FEP and ETC Tiger are included since their inception dates on August 27, 2008 and June 20, 2008, respectively. 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 changed 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 years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007.

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

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differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the years ended December 31, 2009 and 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 to the 2009 presentation. Other than the reclassifications related to the adoption of Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements An Amendment of ARB No. 51*, which is now incorporated into ASC 810-10-65 (see Note 2), these reclassifications had no impact on net income or total equity.

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 our operating subsidiaries (collectively the Operating Companies) as follows:

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, Arizona, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning 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.

- ET Interstate, the parent company of Transwestern and ETC MEP, both of which are Delaware limited liability companies engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

- ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- ETC Tiger Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- HOLP, a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.

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

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

ETC OLP owns an interest in and operates approximately 14,800 miles of in service natural gas gathering and intrastate transportation pipelines, three natural gas processing plants, eleven natural gas treating facilities, eleven natural gas conditioning facilities and three natural gas storage facilities located in Texas.

Revenue in our intrastate transportation and storage operations is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline. 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 HPL System also transports natural gas for a variety of third party customers. Our intrastate transportation and storage segment also generates revenues from fees charged for storing customers working natural gas in our storage facilities. In addition, the use of the Bammel storage facility 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.

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, with an additional 180 miles under construction, extending from Texas through the San Juan Basin to the California border. In addition, we have interests in joint ventures that have 500 miles of interstate natural gas pipeline and 185 miles under construction. 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.

Revenue in our midstream operations is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines (excluding the interstate transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

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 and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the year ended December 31, 2009 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 the 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. Revenues from service labor, transportation, treating, compression and gas processing, are 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.

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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.

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 activities 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.

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We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, 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 senior management and predefined limits and authorizations set forth in our risk management policy.

Regulatory Accounting - Regulatory Assets and Liabilities

Transwestern, part of our interstate transportation segment, is subject to regulation by certain state and federal authorities 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*, now incorporated into ASC 980, 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 insurance limit.

As a result of our acquisition of a natural gas compression equipment business in exchange for ETP Common Units, cash acquired in connection with acquisitions during 2009 exceeded the cash we paid by $30.4 million.

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

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Accounts receivable	$ 28,431	$ 220,635	$ (169,263)	$ 54,347
Accounts receivable from related companies	(29,042)	6,849	(12,557)	(6,003)
Inventories	(101,592)	96,145	(168,430)	196,173
Exchanges receivable	22,074	(7,888)	(4,216)	(3,406)
Other current assets	8,155	(57,041)	(4,701)	53,597
Intangibles and other assets	(4,836)	(40,802)	605	(1,867)
Accounts payable	(16,024)	(296,185)	195,644	(92,172)
Accounts payable to related companies	4,459	(13,957)	29,012	18,564
Exchanges payable	(35,433)	14,254	6,117	3,000
Accrued and other current liabilities	(123,362)	32,377	977	(27,458)
Interest payable	29,963	42,952	33,408	14,844
Other long-term liabilities	1,401	1,741	(680)	1,460
Price risk management liabilities, net	(108,193)	75,874	7,022	30,103
Net change in assets and liabilities, net of effect of acquisitions	$ (323,999)	$ 74,954	$ (87,062)	$ 241,182

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

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
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	$ -	$ -
Capital expenditures accrued	$ 46,134	$ 153,230	$ 87,622	$ 43,498
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 26,237	$ 5,077	$ 3,896	$ 533,625
Issuance of common units in connection with certain acquisitions	$ 63,339	$ 2,228	$ 1,400	$ -
Capital contribution receivable from General Partner	$ 8,932	$ -	$ -	$ -

SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$ 367,924	$ 237,620	$ 51,465	$ 184,993
Cash paid for income taxes	$ 15,447	$ 4,674	$ 9,009	$ 8,583

Marketable Securities

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

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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 $7.4 million, $(6.4) million, $(0.1) million, and $0.3 million were recorded through accumulated other comprehensive income (AOCI), based on the market value of the securities, for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively. The change in value of our available-for-sale securities for the year ended December 31, 2009 includes realized losses of $3.5 million reclassified from AOCI during the period as discussed in Accounts Receivable below.

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 setoff 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, 2009 or 2008; 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 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 collectability.

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 valued at $10.8 million 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 at a fair value of $4.8 million as of December 31, 2008. In 2009, we sold the stock for $7.3 million and recorded a realized loss of $3.6 million, of which $3.5 million was reclassified from AOCI to other income in the consolidated statement of operations.

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Accounts receivable consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas operations	$ 429,849	$ 444,816
Propane	143,011	155,191
Less - allowance for doubtful accounts	(6,338)	(8,750)
Total, net	$ 566,522	$ 591,257

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

	Years Ended December 31,		Four Months Ended	Year Ended
	2009	2008	December 31, 2007	August 31, 2007
Balance, beginning of period	$ 8,750	$ 5,698	$ 5,601	$ 4,000
Accounts receivable written off, net of recoveries	(5,404)	(4,963)	(447)	(2,628)
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Balance, end of period	$ 6,338	$ 8,750	$ 5,698	$ 5,601

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, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 157,103	$ 184,727
Propane	66,686	63,967
Appliances, parts and fittings and other	166,165	23,654
Total inventories	$ 389,954	$ 272,348

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheet and have been recorded in cost of products sold in our consolidated statements of operations.

During 2009, we recorded lower of cost or market adjustments of $54.0 million, which were offset by fair value adjustments related to our application of fair value hedging, of $66.1 million.

During 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 in 2008 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.

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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 imbalances for 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.

Other Current Assets

Other current assets consisted of the following:

	December 31, 2009	December 31, 2008
Deposits paid to vendors	$ 79,694	$ 78,237
Prepaid and other	68,679	75,215
Total other current assets	$ 148,373	$ 153,452

Property, Plant and Equipment

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

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

Capitalized interest is included for pipeline construction projects, except for interstate projects for which an allowance for funds used during construction (AFUDC) is accrued. Interest is capitalized based on the current borrowing rate of 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.

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

	December 31, 2009	December 31, 2008
Land and improvements	$ 87,224	$ 74,731
Buildings and improvements (10 to 40 years)	156,676	129,714
Pipelines and equipment (10 to 83 years)	6,933,189	5,136,357
Natural gas storage (40 years)	100,746	92,457
Bulk storage, equipment and facilities (3 to 83 years)	591,908	533,621
Tanks and other equipment (10 to 30 years)	602,915	578,118
Vehicles (3 to 10 years)	176,946	156,486
Right of way (20 to 83 years)	509,173	358,669
Furniture and fixtures (3 to 10 years)	32,810	28,075
Linepack	53,404	48,108
Pad gas	47,363	53,583
Other (5 to 10 years)	117,896	97,975
	9,410,250	7,287,894
Less Accumulated depreciation	(979,158)	(700,826)
	8,431,092	6,587,068
Plus Construction work-in-process	239,155	1,709,017
Property, plant and equipment, net	$ 8,670,247	$ 8,296,085

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

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Depreciation expense	$ 291,908	$ 244,689	$ 64,569	$ 163,630
Capitalized interest, excluding AFUDC	$ 11,791	$ 21,595	$ 12,657	$ 22,979
AFUDC (both debt and equity components)	$ 10,237	$ 50,074	$ 5,095	$ 3,600

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 4 for a discussion of these joint ventures.

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Goodwill

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. At 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:

	Intrastate Transportation and Storage	Interstate Transportation	Midstream	Retail Propane	All Other	Total
Balance, December 31, 2007	$ 10,327	$ 98,613	$ 24,368	$ 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	10,327	98,613	22,150	612,604	-	743,694
Purchase accounting adjustments	-	-	-	(8,662)	-	(8,662)
Goodwill acquired	-	-	-	33	10,440	10,473
Balance December 31, 2009	$ 10,327	$ 98,613	$ 22,150	$ 603,975	$ 10,440	$ 745,505

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

Intangibles and Other Assets

Intangibles and other 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 assets were as follows:

	December 31, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (3 to 15 years)	$ 24,139	$ (12,415)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,843	(53,123)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(5,638)	23,015	(3,744)
Patents (9 years)	750	(35)	-	-
Other (10 years)	478	(397)	2,677	(2,244)
Total amortizable intangible assets	202,225	(71,608)	210,330	(70,092)
Non-amortizable intangible assets - Trademarks	75,825	-	75,667	-

Total intangible assets	278,050	(71,608)	285,997	(70,092)
Other assets:				
Financing costs (3 to 30 years)	68,597	(24,774)	59,108	(16,586)
Regulatory assets	101,879	(9,501)	98,560	(5,941)
Other	41,316	-	43,153	-
Total intangibles and other long-term assets	$ 489,842	$ (105,883)	$ 486,818	$ (92,619)

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

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Reported in depreciation and amortization	$ 20,895	$ 17,462	$ 6,764	$ 15,532
Reported in interest expense	$ 8,188	$ 6,008	$ 1,710	$ 4,502

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

Years Ending December 31:	
2010	$ 26,991
2011	25,326
2012	21,740
2013	16,310
2014	15,343

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.

Asset Retirement Obligation

We record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, we also recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

We have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates. However, management was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2009 or 2008 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2009	December 31, 2008
Customer advances and deposits	$ 88,430	$ 106,679
Accrued capital expenditures	46,134	153,230

Accrued wages and benefits	25,202	64,692
Taxes other than income taxes	23,294	20,772
Income taxes payable	3,401	14,538
Deferred income taxes	-	589
Other	42,485	73,294
Total accrued and other current liabilities	$ 228,946	$ 433,794

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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.

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, 2009 was $6.75 billion and $6.22 billion, respectively. At December 31, 2008, the aggregate fair value and carrying amount of long-term debt was $5.10 billion and $5.66 billion, respectively.

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. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible level of inputs. 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 that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations.

The following table summarizes the fair value of our financial assets and liabilities as of December 31, 2009 and 2008 based on inputs used to derive their fair values:

Description	Fair Value Measurements at December 31, 2009 Using			Fair Value Measurements at December 31, 2008 Using		
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets:						
Marketable securities	$ 6,055	$ 6,055	$ -	$ 5,915	$ 5,915	$ -
Natural gas inventories	156,156	156,156	-	-	-	-
Commodity derivatives	32,479	20,090	12,389	111,513	106,090	5,423
Liabilities:						
Commodity derivatives	(8,016)	(7,574)	(442)	(43,336)	-	(43,336)
Interest rate swap derivatives	-	-	-	(51,642)	-	(51,642)
	$ 186,674	$ 174,727	$ 11,947	$ 22,450	$ 112,005	$ (89,555)

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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 project costs, is recognized as other income in the period in which it is realized. In March 2008, we received a reimbursement 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:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Received and netted against project costs	$ 6,453	$ 50,050	$ 3,493	$ 10,463
Recorded in other income	(305)	8,352	216	403
Totals	$ 6,148	$ 58,402	$ 3,709	$ 10,866

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and totaled $55.9 million and $112.0 million for the years ended December 31, 2009 and 2008, respectively, $30.7 million for the four months ended December 31, 2007 and $58.6 million for the year ended August 31, 2007. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

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

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

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 Second Amended and Restated Agreement of Limited Partnership (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,

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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. 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 years ended December 31, 2009 and 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 $3.8 million, $3.4 million, $1.2 million and $1.2 million, respectively. As of December 31, 2009, the amount of tax goodwill to be amortized over the next 13 years for which HHI will receive a remedial income allocation is approximately $132.8 million.

As a limited partnership, we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, our non-qualifying income did not exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes, under which 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.

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Accounting for Derivative Instruments and Hedging Activities

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.

We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention gas and hedge location price differentials related to the transportation of natural gas.

Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. 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.

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.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

We attempt to maintain balanced positions in our marketing 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 most of 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 position and results of operations, either favorably or unfavorably.

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 earnings. 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 do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We are exposed to market risk for changes in interest rates related to our revolving credit facilities. We previously have managed 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. See Note 12 for additional information related to interest rate derivatives

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, 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 7). 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.

Unit-Based Compensation

We recognize compensation expense for equity awards issued to employees over the vesting period based on the grant-date fair value. 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.

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New Accounting Standards

A retrospective adjustment has been made to prior period income per limited partner unit presented in our consolidated statements of operations to conform to current period presentation as discussed further below.

Accounting Standards Codification. On July 1, 2009, the Financial Accounting Standards Board (FASB) instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The *FASB Accounting Standards Codification* (ASC) is now the single authoritative source for GAAP. Although the implementation of ASC has no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Noncontrolling Interests. On January 1, 2009, we adopted SFAS 160, now incorporated into ASC 810-10, which established new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, the new standard requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent s equity. The amount of new income attributable to the noncontrolling interest is included in consolidated net income on the face of the income statement. The new standard clarifies that changes in a parent s ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, the new standard requires that a parent recognizes a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss is measured using the fair value of the noncontrolling equity investment on the deconsolidation date. This standard also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. The adoption of this standard did not have a significant impact on our financial position or results of operations. However, it did result in certain changes to our financial position presentation.

Upon adoption, we reclassified $1.1 million of minority interest expense to net income attributable to noncontrolling interest in our consolidated statements of operations for the year ended August 31, 2007. Net income per limited partner unit has not been affected as a result of the adoption of this standard.

Earnings per Unit. On January 1, 2009, we adopted a new methodology for calculating earnings per unit to reflect recently ratified changes to accounting standards. This new standard was originally issued as Emerging Issues Task Force Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships,* and is now incorporated into ASC 260-10.

Based on the terms of our Partnership Agreement, the new methodology requires us to allocate any excess undistributed earnings to the general partner and limited partners based on their respective ownership interests, with none of the excess undistributed earnings allocated to the incentive distribution rights (IDRs). Previously, we allocated a portion of the excess undistributed earnings to the IDRs. Thus, for periods where earnings exceed distributions, the new methodology will result in a higher income per limited partner unit than our previous approach. For periods where distributions exceed earnings, the new methodology is consistent with our previous approach.

On January 1, 2009, we also adopted FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities,* which is now incorporated into ASC 260-10-45. This standard 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. Based on unvested unit awards outstanding at the time of adoption, application of this standard did not have a material impact on our computation of earnings per unit.

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The following financial table sets forth the effect of the retrospective application of the new methodology under ASC 260-10-55 and ASC 260-10-45:

	Year Ended December 31, 2008		Four Months Ended December 31, 2007		Year Ended August 31, 2007	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted	Originally Reported	As Adjusted
Basic net income per limited partner unit	$ 3.75	$ 3.74	$ 1.22	$ 1.24	$ 3.32	$ 3.32
Diluted net income per limited partner unit	$ 3.74	$ 3.74	$ 1.21	$ 1.24	$ 3.31	$ 3.31

Business Combinations. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations,* which is now incorporated into ASC 805. The new standard significantly changes the accounting for business combinations and includes a substantial number of new disclosure requirements. The new standard requires an acquiring entity to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions and changes the accounting treatment for certain specific items, including:

- Acquisition costs are generally expensed as incurred;
- Noncontrolling interests (previously referred to as minority interests) are valued at fair value at the acquisition date;
- In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;
- Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

Our adoption of this standard did not have an immediate impact on our financial position or results of operations; however, it has impacted the accounting for our business combinations subsequent to adoption.

Derivative Instruments and Hedging Activities. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133,* which is now incorporated into ASC 815. This standard changed the disclosure requirements for derivative instruments and hedging activities, including requirements for qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The standard only affected disclosure requirements; therefore, our adoption did not impact our financial position or results of operations.

Equity Method Investment Accounting. On January 1, 2009, we adopted Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations,* which is now incorporated into ASC 323-10. This standard 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, and 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. Our adoption did not have a material impact on our financial position or results of operations.

Subsequent Events. During 2009, we adopted Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events*, which is now incorporated into ASC 855. Under this standard, we are required to evaluate subsequent events through the date that our financial statements are issued and also required to disclose the date through which subsequent events are evaluated. The adoption of this standard does not change our current practices with respect to evaluating, recording and disclosing subsequent events; therefore, our adoption of this statement during the second quarter had no impact on our financial position or results of operations.

3. ACQUISITIONS:

Proposed Transaction

We have agreed to purchase a natural gas gathering company which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale. The purchase price is $150 million in cash, excluding certain adjustments as defined in the purchase agreement, and the acquisition is expected to close in March 2010.

2009

In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas, in exchange for our issuance of 1,450,076 Common Units having an aggregate market value of approximately $63.3 million on the closing date. In connection with this transaction, we received cash of $41.1 million, assumed total liabilities of $30.5 million, which includes $8.4 million in notes payable and recorded goodwill of $8.7 million. In addition, we acquired ETG in August 2009. See Note 14.

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 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

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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 ETE 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 formed our interstate transportation segment.

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 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 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.

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

	Intrastate Transportation and Storage and Midstream 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 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.

Regulatory assets, included in intangible and other 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.

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We recorded the following intangible assets and goodwill in conjunction with the fiscal year 2007 acquisitions described above:

	Intrastate Transportation and Storage and Midstream 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.

4. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

We are party to an agreement with Kinder Morgan Energy Partners, L.P. (KMP) for a 50/50 joint development of the Midcontinent Express pipeline. Construction of the approximately 500-mile pipeline was completed and natural gas transportation service commenced August 1, 2009 on the pipeline from Delhi, Louisiana, to an interconnect with the Transco interstate natural gas pipeline in Butler, Alabama. Interim service began on the pipeline from Bennington, Oklahoma, to Delhi in April 2009. In July 2008, Midcontinent Express Pipeline LLC (MEP), the entity formed to construct, own and operate this pipeline, completed an open season with respect to a capacity expansion of the pipeline from the current capacity of 1.4 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to an interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is expected to be completed in the latter part of 2010. This expansion was approved by the Federal Energy Regulatory Commission (the FERC) in September 2009.

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

Fayetteville Express Pipeline LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-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. In December 2009, Fayetteville Express Pipeline LLC (FEP), the entity formed to construct, own and operate this pipeline, received FERC approval of its application for authority to construct and operate this pipeline. That order is currently subject to a limited request for rehearing. The

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pipeline is expected to have an initial capacity of 2.0 Bcf/d. The pipeline project is expected to be in service by the end of 2010. 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 Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

Capital Contributions to Affiliates

During the year ended December 31, 2009, we contributed $664.5 million to MEP. FEP s capital expenditures are being funded under a credit facility. All of our contributions to FEP were reimbursed to us in 2009, including $9.0 million that we contributed in 2008.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, MEP and FEP (on a 100% basis):

	December 31, 2009	December 31, 2008
Current assets	$ 33,794	$ 9,953
Property, plant and equipment, net	2,576,031	1,012,006
Other assets	19,658	-
Total assets	$ 2,629,483	$ 1,021,959
Current liabilities	$ 105,951	$ 163,379
Non-current liabilities	1,198,882	840,580
Equity	1,324,650	18,000
Total liabilities and equity	$ 2,629,483	$ 1,021,959

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Revenue	$ 98,593	$ -	$ -	$ -
Operating income	47,818	-	-	-
Net income	36,555	1,057	-	-

As stated above, MEP was placed into service during 2009.

5. <u>NET INCOME PER LIMITED PARTNER UNIT</u>:

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 IDRs pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. As discussed in Note 2, the adoption of a new accounting principle required us to change our calculation of earnings per unit during periods where earnings exceeded distributions; earnings in excess of distributions are now allocated to the General Partner and Limited Partners based on their respective ownership interests. Previously, a portion of earnings in excess of distributions had been allocated to the General

Partner with respect to the IDRs. We have applied this change in accounting principle retrospectively; therefore, earnings per unit amounts for prior periods have been restated.

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

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income attributable to partners	$ 791,542	$ 866,023	$ 261,824	$ 676,139
General Partner s interest in net income	365,362	315,896	91,011	235,876
Limited Partner s interest in net income	426,180	550,127	170,813	440,263
Additional earnings allocated from General Partner	468	-	-	-
Distributions on employee unit awards, net of allocation to General Partner	(2,760)	(153)	-	-
Net income available to Limited Partners	$ 423,888	$ 549,974	$ 170,813	$ 440,263
Weighted average Limited Partner units basic	167,337,192	146,871,261	137,624,934	132,618,053
Basic net income per Limited Partner unit	$ 2.53	$ 3.74	$ 1.24	$ 3.32
Weighted average Limited Partner units	167,337,192	146,871,261	137,624,934	132,618,053
Dilutive effect of Unit Grants	431,789	219,347	388,432	259,099
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	167,768,981	147,090,608	138,013,366	132,877,152
Diluted net income per Limited Partner unit	$ 2.53	$ 3.74	$ 1.24	$ 3.31

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6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2009	December 31, 2008	
ETP Senior Notes:			
5.95% Senior Notes, due February 1, 2015	$ 750,000	$ 750,000	Payable upon maturity. Interest is paid semi-annually.
5.65% Senior Notes, due August 1, 2012	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.125% Senior Notes, due February 15, 2017	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.625% Senior Notes, due October 15, 2036	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.0% Senior Notes, due July 1, 2013	350,000	350,000	Payable upon maturity. Interest is paid semi-annually.
6.7% Senior Notes, due July 1, 2018	600,000	600,000	Payable upon maturity. Interest is paid semi-annually.
7.5% Senior Notes, due July 1, 2038	550,000	550,000	Payable upon maturity. Interest is paid semi-annually.
9.7% Senior Notes due March 15, 2019	600,000	600,000	Put option on March 15, 2012. Payable upon maturity. Interest is paid semi-annually.
8.5% Senior Notes due April 15, 2014	350,000	-	Payable upon maturity. Interest is paid semi-annually.
9.0% Senior Notes due April 15, 2019	650,000	-	Payable upon maturity. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Notes, due November 17, 2014	88,000	88,000	Payable upon maturity. Interest is paid semi-annually.
5.54% Senior Unsecured Notes, due November 17, 2016	125,000	125,000	Payable upon maturity. Interest is paid semi-annually.
5.64% Senior Unsecured Notes, due May 24, 2017	82,000	82,000	Payable upon maturity. Interest is paid semi-annually.
5.89% Senior Unsecured Notes, due May 24, 2022	150,000	150,000	Payable upon maturity. Interest is paid semi-annually.
6.16% Senior Unsecured Notes, due May 24, 2037	75,000	75,000	Payable upon maturity. Interest is paid semi-annually.
5.36% Senior Unsecured Notes, due December 9, 2020	175,000	-	Payable upon maturity. Interest is paid semi-annually.
5.66% Senior Unsecured Notes, due December 9, 2024	175,000	-	Payable upon maturity. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	24,000	36,000	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	Matured in November 2009.
7.26% Series B Senior Secured Notes	6,000	8,000	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	4,571	9,142	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	5,750	11,500	Annual payments of $5,750 due each August 15 through 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	33,100	45,550	Annual payments of $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	6,000	7,000	Annual payments of $1,000 due each August 15 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.
7.89% Series H Senior Secured Notes	5,091	5,818	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 due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility	150,000	902,000	See terms below under ETP Credit Facility .
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	10,000	See terms below under HOLP Credit Facility .
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 8.06% and 7.91%	7,898	11,249	Due in installments through 2014.

for December 31, 2009 and 2008, respectively			
Other	2,224	2,565	Due in installments through 2024.
Unamortized discounts	(12,829)	(13,477)	
	6,217,805	5,663,747	
Current maturities	(40,887)	(45,198)	
	$ 6,176,918	$ 5,618,549	

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

2010	$	40,887
2011		44,567
2012		572,838
2013		372,523
2014		443,519
Thereafter		4,743,471
	$	6,217,805

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. Interest on the ETP Senior Notes is paid semi-annually.

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.

In April 2009, we completed a public offering of $350.0 million aggregate principal amount of 8.5% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.0% Senior Notes due 2019 (collectively the 2009 ETP Notes). The offering of the 2009 ETP Notes closed on April 7, 2009 and we used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

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, $307.0 million aggregate principal amount of notes issued in May 2007, and $350.0 million aggregate principal amount of notes issued in December 2009. The proceeds from the notes issued in December 2009 were used by Transwestern to repay amounts under an intercompany loan agreement. 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 payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. Interest is paid semi-annually.

Transwestern s debt agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

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).

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 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 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, 2009, there was a balance outstanding in the ETP Credit Facility of $150.0 million in revolving credit loans and approximately $62.2 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2009 was 0.78%. The total amount available under the ETP Credit Facility, as of December 31, 2009, which is reduced by any letters of credit, was approximately $1.79 billion. 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. 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 through June 30, 2011, which may be expanded to $150.0 million. 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 in the credit agreement for the HOLP Credit Facility, 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, 2009 of approximately $1.2 billion). At December 31, 2009, there was $10.0 million outstanding in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of December 31, 2009 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 Companies, 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 further 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;

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- 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 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. This financial covenant could therefore restrict our ability to make cash distributions to our Unitholders, our general partner and the holder of our incentive distribution rights.

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 revolving 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 Companies ability to incur additional debt and/or our ability to pay distributions.

We are required to assess compliance quarterly and we were in compliance with all requirements, limitations, and covenants related to our debt agreements as of December 31, 2009.

7. PARTNERS CAPITAL

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 of December 31, 2009, there were issued and outstanding 179,274,747 Common Units representing an aggregate 98.1% Limited Partner

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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.

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.

IDRs 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 IDRs.

Common Units

The change in Common Units is as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Number of Units, beginning of period	152,102,471	142,069,957	136,981,221	110,726,999
Common Units issued in connection with public offerings	23,575,000	9,662,500	5,000,000	-
Common Units issued in connection with certain acquisitions	1,450,076	53,893	27,348	-
Common Units issued in connection with the Equity Distribution Agreement	1,891,691			
Issuance of restricted Common Units	-	-	-	167,265
Conversion of Class G Units to Common Units	-	-	-	26,086,957
Issuance of Common Units under the equity incentive plans	255,509	316,121	61,388	-
Number of Units, end of period	179,274,747	152,102,471	142,069,957	136,981,221

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

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Public Offerings

The following table summarizes our public offerings of Common Units, all of which have been registered under the Securities Act of 1933, as amended:

Date	Number of Common Units (1)	Price per Unit	Net Proceeds	Use of Proceeds
December 2007 (2)	5,750,000	$ 48.81	$ 269.4	(3)
July 2008	8,912,500	39.45	337.5	(4)
January 2009	6,900,000	34.05	225.4	(4)
April 2009	9,775,000	37.55	352.4	(5)
October 2009	6,900,000	41.27	276.0	(4)
January 2010	9,775,000	44.72	423.6	(4)(5)

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.
(2) Amounts include the exercise of the overallotment option by the underwriters in January 2008.
(3) Proceeds were used to repay amounts outstanding under ETP s prior term loan facility.
(4) Proceeds were used to repay amounts outstanding under the ETP Credit Facility.
(5) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

Equity Distribution Program

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC (UBS). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, common units having an aggregate offering price of up to $300.0 million. Sales of the units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During 2009, we issued 2,079,593 of our common units pursuant to this agreement, 1,891,691 of which have been settled as of December 31, 2009. The proceeds of approximately $81.5 million, net of commissions, were used to repay amounts outstanding under our revolving credit facility.

Equity Incentive Plan Activity

As discussed in Note 8, we issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Other Common Unit 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. During fiscal year 2007, we converted all of the Class G Units to Common Units.

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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.

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 IDRs 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, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received $0.25 per unit for such quarter (the minimum quarterly distribution);

Second, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received $0.275 per unit for such quarter (the first target distribution);

Third, 87% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, 13% to the holders of IDRs, pro rata, until each Common Unit has received at least $0.3175 per unit for such quarter (the second target distribution);

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Fourth, 77% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, 23% to the holders of IDRs, pro rata, until each Common Unit has received at least $0.4125 per unit for such quarter; (the third target distribution); and

Fifth, thereafter, 52% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, 48% to the holders of Incentive Distribution Rights, pro rata.

The allocation of distributions among the Common and Class E Unitholders and the General Partner is based on their respective interests as of the record date for such distributions. As of December 31, 2009, the Common and Class E Unitholders collectively held 98.1% of the ownership interests in us, and the General Partner held a 1.9% interest.

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

Distributions declared during the periods presented below are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2009	November 9, 2009	November 16, 2009	$ 0.89375
	August 7, 2009	August 14, 2009	0.89375
	May 8, 2009	May 15, 2009	0.89375
	February 6, 2009	February 13, 2009	0.89375
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

(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.

On January 28, 2010, we declared a cash distribution for the fourth quarter ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized. We paid this distribution on February 15, 2010 to Unitholders of record at the close of business on February 8, 2010.

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The total amounts of distributions declared during the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007 are as follows (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 629,263	$ 537,731	$ 160,672	$ 396,095
Class E Units (1)	12,484	12,484	3,121	12,484
Class G Units (2)	-	-	-	40,598
General Partner interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$ 1,011,738	$ 866,112	$ 254,678	$ 685,235

(1) See explanation of Class E Units above.
(2) Distributions declared prior to the Class G Units converting to Common Units (see detail above).

Upon their conversion to Common Units, the Class 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 AOCI, net of tax:

	December 31, 2009	December 31, 2008
Net gain on commodity related hedges	$ 1,991	$ 8,735
Net gain (loss) on interest rate hedges	(125)	161
Unrealized gains (losses) on available-for-sale securities	4,941	(5,983)
Total AOCI, net of tax	$ 6,807	$ 2,913

8. 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 LLC, a subsidiary or their affiliates, and members of ETP LLC 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, 2009, a total of 4,213,111 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, 2009, 5,578 ETP Common Units were available for future grants under the 2004 Unit Plan.

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Employee Grants

Prior to December 2007, substantially all of the awards granted to employees 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 equity incentive plans generally require the continued employment of the recipient during the vesting period; however, the Compensation Committee has complete discretion to accelerate the vesting of unvested unit awards.

In 2008 and 2009, the Compensation Committee approved the grant of new unit awards, which vest 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 2008 and 2009, 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.

Director Grants

Under our equity incentive plans, our non-employee directors each receive unvested ETP Common Units with a grant-date fair value of $50,000 each year. These non-employee director grants vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

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Award Activity

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2008	1,372,568	$ 36.83
Awards granted	763,190	43.56
Awards vested	(336,386)	36.02
Awards forfeited	(108,780)	39.17
Unvested awards as of December 31, 2009	1,690,592	39.88

The balance above for unvested awards as of December 31, 2008 includes 150,852 unit awards with a grant-date fair value of $43.96 per unit, which were granted prior to 2008 and were subject to a performance condition, as described above. These remaining performance awards vested in 2009, and none of the unvested unit awards outstanding as of December 31, 2009 contain performance conditions.

During the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, the weighted average grant-date fair value per unit award granted was $43.56, $33.86, $42.46 and $43.73, respectively. The total fair value of awards vested was $14.7 million, $14.6 million, $3.3 million and $7.9 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2009, a total of 1,690,592 unit awards remain unvested, for which ETP expects to recognize a total of $50.9 million in compensation expense over a weighted average period of 1.9 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of the entity that owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officers. 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. 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.

During the years ended December 31, 2008 and August 31, 2007, unvested rights related to 450,000 ETE common units and 675,000 ETE common units, respectively, with aggregate grant-date fair values of $10.3 million and $23.5 million, respectively, were awarded to ETP officers. During the year ended December 31, 2008, unvested rights related to 240,000 ETE common units were forfeited. During the years ended December 31, 2009 and 2008 and the four months ended December 31, 2007, ETP officers vested in rights related to 165,000 ETE common units, 135,000 ETE common units, and 55,000 ETE common units, respectively, with aggregate fair values upon vesting of $4.6 million, $3.5 million, and $1.9 million, respectively.

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. For the years ended December 31, 2009 and 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 $6.4 million, $3.5 million, $3.6 million and $5.2 million, respectively, as a result of these awards.

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As of December 31, 2009, rights related to 530,000 ETE common units remain outstanding, for which we expect to recognize a total of $6.8 million in compensation expense over a weighted average period of 1.9 years

9. INCOME TAXES:

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

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Current expense (benefit):				
Federal	$ (8,851)	$ (180)	$ 2,990	$ 7,896
State	9,662	12,216	5,705	9,803
Total	811	12,036	8,695	17,699
Deferred expense (benefit):				
Federal	11,541	(5,634)	1,482	(4,598)
State	425	278	612	557
Total	11,966	(5,356)	2,094	(4,041)
Total income tax expense (benefit)	$ 12,777	$ 6,680	$ 10,789	$ 13,658

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 years ended December 31, 2009 and 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 $8.5 million, $10.5 million, $3.9 million and $6.9 million, respectively.

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 is summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate, net of federal benefit	1.03%	1.25%	1.82%	1.25%
Earnings not subject to tax at the Partnership level	(34.44%)	(35.48%)	(32.86%)	(34.25%)

Effective tax rate	1.59%	0.77%	3.96%	2.00%

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, 2009	December 31, 2008
Property, plant and equipment	$ 112,707	$ 105,032
Other, net	290	(3,846)
Total deferred tax liability	112,997	101,186
Less current deferred tax liability	-	589
Total long-term deferred tax liability	$ 112,997	$ 100,597

10. MAJOR CUSTOMERS AND SUPPLIERS:

Our major customers are in the natural gas operations segments. Our natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while our NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively. Management believes that our portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer accounted for 10% or more of our consolidated revenue.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Propane segments				
Unaffiliated:				
M.P. Oils, Ltd.	15.1%	14.9%	14.2%	20.7%
Targa Liquids	14.3%	15.0%	15.9%	22.6%
Affiliated:				
Enterprise	50.3%	50.7%	50.6%	22.1%

Enterprise GP Holdings, L.P. and its subsidiaries (Enterprise or EPE) became related parties on May 7, 2007 as discussed in Note 14. Titan purchases the majority of its propane from Enterprise pursuant to an agreement that expires in March 2010 and contains renewal and extension options.

We sold our investment in M-P Energy in October 2007. In connection with the sale, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 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.

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11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline. Approval from the FERC is still pending.

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 that resolved the primary components of the rate case. Transwestern s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than 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. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service effective March 2009.

Guarantees

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (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 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 commitment amount under the MEP Facility was originally $1.4 billion. In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by us or KMP. In October 2009, the members made additional capital contributions to MEP, which MEP used to further reduce the outstanding borrowings under the MEP Facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275.0 million.

As of December 31, 2009, MEP had $29.5 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 $14.7 million and $16.6 million, respectively, as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.3%.

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FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the FEP Facility). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP 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 FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of December 31, 2009, FEP had $355.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP s outstanding borrowings was $177.5 million as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.2%.

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 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 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $19.8 million, $17.2 million, $9.4 million and $33.2 million for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, respectively.

Future minimum lease commitments for such leases are:

2010	$	27,216
2011		24,786
2012		22,522
2013		20,385
2014		17,907
Thereafter		214,088

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 390,564 MMBtu/d. Long-term contracts require delivery of up to 125,551 MMBtu/d and extend through May 2014.

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 a transportation agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 100,000 MMBtu per year through 2012. We also have two natural gas storage agreements with TXU Shipper to store gas at two natural gas facilities that are part of the ET Fuel System that expire in 2012. As of December 31, 2009 and 2008 and August 31, 2007, 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 $11.7 million, $10.7 million and $10.8 million in additional fees during the second quarters of 2009 and 2008 and the third fiscal quarter of 2007, 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 that expires in June 2012. Exxon Mobil Corporation (ExxonMobil) and XTO announced an agreement whereby ExxonMobil will acquire XTO. The pending acquisition, expected to be completed in the second quarter of 2010, is not expected to result in any changes to these commitments.

We also have two long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts require an aggregated capacity of approximately 238,000 MMBtu/d of natural gas and extend through 2011.

Titan has a purchase contract with Enterprise (see Note 14) to purchase the majority of Titan s propane requirements. The contract continues until March 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 propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

We have commitments to make capital contributions to our joint ventures, for which we expect to make capital contributions of between $90 million and $105 million during 2010.

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 coverage 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 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 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 NGA. The FERC alleged that we 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. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the

Waha and Permian Hubs in west Texas on two dates. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. The FERC specified that it was also seeking to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices. In February 2008, the FERC s Enforcement Staff also 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 the 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.

On August 26, 2009, we entered into a settlement agreement with the FERC s Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement settles all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims against us, including existing litigation claims as well as any new claims that may be asserted against this fund. An administrative law judge appointed by the FERC will determine the validity of any third party claim against this fund. Any party who receives money from this fund will be required to waive all claims against us related to this matter. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by exceeding the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

We made the $5.0 million payment and established the $25.0 million fund in October 2009. The allocation of the $25.0 million fund is expected to be determined in 2010.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE alleging 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. In one of these cases, the Texas Supreme Court ruled on July 3, 2009 that the state district court erred in ruling that a plaintiff was entitled to pre-arbitration discovery and therefore remanded to the state district court with a direction to rule on our original motion to compel arbitration pursuant to the terms of the arbitration clause in a natural gas contract between us and the plaintiff. This plaintiff has filed a motion with the Texas Supreme Court requesting a rehearing of the ruling.

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. This action is currently on appeal before the First Court of Appeals, Houston, Texas.

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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 NYMEX in violation of the Commodity Exchange Act (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 March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs motion for reconsideration. On September 28, 2009, these decisions were appealed by the plaintiffs to the United States Court of Appeals for the Fifth Circuit.

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 March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff s motion and granted our motion to dismiss the complaint. On September 10, 2009, this decision was appealed by the plaintiff to the United States Court of Appeals for the Fifth Circuit.

We are expensing the legal fees, consultants fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obliged to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment 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

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result of the final resolution of these matters is greater than the amount of our 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. On March 17, 2009, the Tenth Circuit affirmed the District Court s dismissal. Appellant sought appellate rehearing on the matter and the petition for rehearing was denied on May 4, 2009. A petition for writ of certiorari was filed by the Appellant on August 3, 2009, and the Supreme Court denied the petition for writ of certiorari on October 5, 2009. We do not believe the outcome of this case will have a material adverse effect on our financial position, results of operations or cash flows.

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.

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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 of December 31, 2009 and 2008, accruals of approximately $11.1 million and $8.5 million, respectively, were recorded related to deductibles. 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, an accrual of $21.0 million 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, and we did not have any such accruals as of December 31, 2009.

Environmental Matters

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 $8.6 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. 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

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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, 2009 or our December 31, 2008 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of December 31, 2009 and 2008, accruals on an undiscounted basis of $12.6 million and $13.3 million, respectively, were 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

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integrity issues raised by the assessment and analysis. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

See Note 2 for further discussion of our accounting for derivative instruments and hedging activities.

Commodity Price Risk

The following table details the outstanding commodity-related derivatives:

		December 31, 2009		December 31, 2008	
	Commodity	Notional Volume MMBtu	Maturity	Notional Volume MMBtu	Maturity
Mark to Market Derivatives					
Basis Swaps IFERC/NYMEX	Gas	72,325,000	2010-2011	15,720,000	2009-2011
Swing Swaps IFERC	Gas	(38,935,000)	2010	(58,045,000)	2009
Fixed Swaps/Futures	Gas	4,852,500	2010-2011	(20,880,000)	2009-2010
Options - Puts	Gas	2,640,000	2010	-	N/A
Options - Calls	Gas	(2,640,000)	2010	-	N/A
Forwards/Swaps - in Gallons	Propane/Ethane	6,090,000	2010	47,313,002	2009
Fair Value Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(22,625,000)	2010	-	N/A
Fixed Swaps/Futures	Gas	(27,300,000)	2010	-	N/A
Hedged Item - Inventory	Gas	27,300,000	2010	-	N/A
Cash Flow Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(13,225,000)	2010	(9,085,000)	2009
Fixed Swaps/Futures	Gas	(22,800,000)	2010	(9,085,000)	2009
Forwards/Swaps - in Gallons	Propane/Ethane	20,538,000	2010	-	N/A

We expect gains of $2.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in 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 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. There were no gains or losses associated with trading activities during the year ended December 31, 2009.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We have previously managed a portion of our current and future interest rate exposures by utilizing interest rate swaps. As of December 31, 2009, we do not have any interest rate swaps outstanding.

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In December 2009, we settled forward starting swaps with notional amounts of $500.0 million for a cash payment of $11.1 million. In April 2009, we terminated forward starting swaps with notional amounts of $100.0 million and $150.0 million for an insignificant amount.

In January 2010, we entered into interest rate swaps with notional amounts of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate that mature in July 2013 and February 2015, respectively. These swaps hedge against changes in the fair value of our fixed rate debt.

Derivative Summary

The following table provides a balance sheet overview of the Partnership s derivative assets and liabilities as of December 31, 2009 and December 31, 2008:

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Derivatives designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 669	$ 10,665	$ (24,035)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	8,443	918	(201)	(119)
Total derivatives designated as hedging instruments		$ 9,112	$ 11,583	$ (24,236)	$ (1,623)
Derivatives not designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	72,851	432,614	(36,950)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	3,928	17,244	(241)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	-	-	-	(51,643)
Total derivatives not designated as hedging instruments		$ 76,779	$ 449,858	$ (37,191)	$ (443,282)
Total derivatives		$ 85,891	$ 461,441	$ (61,427)	$ (444,905)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required 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 for non-exchange traded derivatives. 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 vendors within other current assets in the consolidated balance sheets. The Partnership had net deposits with counterparties of $79.7 million and $78.2 million as of December 31, 2009 and December 31, 2008, respectively.

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The following tables detail the effect of the Partnership s derivative assets and liabilities in the consolidated statements of operations for the periods presented:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 3,143	$ 17,461	$ 21,406	$ 181,765
Interest Rate Swap Derivatives	Interest Expense	-	-	-	(4,719)
Total		$ 3,143	$ 17,461	$ 21,406	$ 177,046

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 9,924	$ 42,874	$ 8,673	$ 162,340
Interest Rate Swap Derivatives	Interest Expense	287	646	(51)	920
Total		$ 10,211	$ 43,520	$ 8,622	$ 163,260

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ -	$ (8,347)	$ 8,472	$ 183
Interest Rate Swap Derivatives	Interest Expense	-	-	-	(1,813)
Total		$ -	$ (8,347)	$ 8,472	$ (1,630)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Years Ended December 31,		Four Months Ended	Year Ended
		2009	2008	December 31, 2007	August 31, 2007
Derivatives in fair value hedging relationships:					
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ 60,045	$ -	$ -	$ -
Total		$ 60,045	$ -	$ -	$ -

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	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Years Ended December 31,		Four Months Ended December 31, 2007	Year Ended August 31, 2007
		2009	2008		
Derivatives not designated as hedging instruments:					
Commodity Derivatives	Cost of Products Sold	$ 99,807	$ 12,478	$ 9,886	$ 30,028
Trading Commodity Derivatives	Revenue	-	(28,283)	(2,298)	5,228
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	39,239	(50,989)	(1,013)	31,032
Total		$ 139,046	$ (66,794)	$ 6,575	$ 66,288

We recognized an $18.6 million unrealized loss, a $35.5 million unrealized gain, a $13.2 million unrealized gain and an $8.5 million unrealized loss on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships and amounts classified as trading activity) for the years ended December 31, 2009 and 2008, four months ended December 31, 2007 and the year August 31, 2007, respectively. In addition, for the year ended December 31, 2009, we recognized unrealized gains of $48.6 million on commodity derivatives and related hedged inventory accounted for as fair value hedges. There were no unrealized gains or losses on fair value hedging commodity derivatives in the prior years since we commenced fair hedge accounting on our storage inventory in April 2009.

Credit Risk

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

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

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

13. RETIREMENT BENEFITS:

We sponsor a 401(k) savings plan, which covers virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. Prior to 2009, employer matching contributions were discretionary. We made matching contributions of $9.8 million, $9.7 million, $2.6 million and $8.5 million to the 401(k) savings plan for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively.

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14. 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. In addition to the purchase of ETE Common Units, Enterprise acquired a non-controlling equity interest in ETE s General Partner, LE GP, LLC (LE GP). As a result of these transactions, EPE and its subsidiaries are considered related parties for financial reporting purposes.

On December 23, 2009, Dan L. Duncan and Ralph S. Cunningham were appointed as directors of ETE s general partner. Mr. Duncan is Chairman and a director of EPE Holdings, LLC, the general partner of Enterprise; Chairman and a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., or EPD; and Group Co-Chairman of EPCO, Inc. TEPPCO Partners, L.P., or TEPPCO, is also an affiliate of EPE. Dr. Cunningham is the President and Chief Executive Officer of EPE Holdings, LLC, the general partner of Enterprise. These entities and other affiliates of Enterprise are referred to herein collectively as the Enterprise Entities. Mr. Duncan directly or indirectly beneficially owns various interests in the Enterprise Entities, including various general partner interests and approximately 77.1% of the common units of Enterprise and approximately 34% of the common units of EPD. On October 26, 2009, TEPPCO became a wholly owned subsidiary of Enterprise.

Our propane operations routinely enter into purchases and sales of propane with certain of the Enterprise Entities, including purchases under a long-term contract of Titan to purchase the majority of its propane requirements through certain of the Enterprise Entities. This agreement was in effect prior to our acquisition of Titan in 2006, and expires in March 2010 and contains renewal and extension options.

From time to time, our natural gas operations purchase from, and sell to, the Enterprise Entities natural gas and NGLs, in the ordinary course of business. We have a monthly natural gas storage contract with TEPPCO. Our natural gas operations and the Enterprise Entities transport natural gas on each other s pipelines and share operating expenses on jointly-owned pipelines.

The following table presents sales to and purchases from affiliates of Enterprise. Amounts reflected below for the year ended August 31, 2007 include transactions beginning on May 7, 2007, the date Enterprise became an affiliate. Volumes are presented in thousands of gallons for propane and NGLs and in billions of Btus for natural gas:

		Years Ended December 31,				Four Months Ended December 31,		Year Ended August 31,	
		2009		2008		2007		2007	
	Product	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars
Propane Operations:									
Sales	Propane	20,370	$ 14,046	13,230	$ 19,769	2,982	$ 4,619	1,470	$ 1,725
	Derivatives	-	5,915	-	2,442	-	1,857	-	22
Purchases	Propane	307,525	$ 305,148	318,982	$ 472,816	125,141	$ 192,580	61,660	$ 74,688
	Derivatives	-	38,392	-	20,993	-	-	-	1
Natural Gas Operations:									
Sales	NGLs	477,908	$ 374,020	58,361	$ 96,974	3,240	$ 4,726	464	$ 648
	Natural Gas	11,532	44,212	6,256	52,205	2,036	11,452	1,495	9,768
	Fees	-	(3,899)	-	5,093	-	610	-	-
Purchases	Natural Gas Imbalances	176	$ 1,164	3,488	$ (6,485)	313	$ (911)	3,120	$ 22,677
	Natural Gas	10,561	49,559	13,457	120,837	3,577	23,341	1,541	7,501
	Fees	-	(2,195)	-	876	-	311	-	-

As of December 31, 2009 and 2008, Titan had forward mark-to-market derivatives for approximately 6.1 million and 45.2 million gallons of propane at a fair value asset of $3.3 million and a fair value liability

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of $40.1 million, respectively, with Enterprise. In addition, as of December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 20.5 million gallons of propane at a fair value asset of $8.4 million with Enterprise.

The following table summarizes the related party balances with Enterprise on our consolidated balance sheets:

	December 31, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 47,005	$ 11,558
Accounts payable	3,518	567
Imbalance payable	694	(547)
Propane Operations:		
Accounts receivable	$ 3,386	$ 111
Accounts payable	31,642	33,308

Accounts receivable from related companies excluding Enterprise consist of the following:

	December 31, 2009	December 31, 2008
ETP GP	$ 221	$ 122
ETE	5,255	2,632
MEP	632	2,805
McReynolds Energy	-	202
Energy Transfer Technologies, Ltd.	-	16
Others	870	449
Total accounts receivable from related companies excluding Enterprise	$ 6,978	$ 6,226

Effective August 17, 2009, we acquired 100% of the membership interests of Energy Transfer Group, L.L.C. (ETG), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. (ETT). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of our General Partner s general partner and the other of which is controlled by a member of ETP s management. In exchange, the former members acquired the right to receive (in cash or Common Units) future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG may receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

Prior to our acquisition of ETG in August 2009, our natural gas midstream and intrastate transportation and storage operations secured compression services from ETT. The terms of each arrangement to provide compression services were, in the opinion of independent directors of the General Partner, no more or less favorable than those available from other providers of compression services. During the years ended December 31, 2009 (through the ETG acquisition date) and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, we made payments totaling $3.4 million, $9.4 million, $0.8 million and $2.4 million, respectively, to ETG for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations.

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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 each of the years ended December 31, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

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:

- intrastate transportation and storage
- interstate transportation
- midstream

retail propane and other retail propane related 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 and natural gas compression services 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.

See Business Operations in Note 1 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 and administrative expenses, gains (losses) on disposal of assets, interest expense, equity in earnings (losses) from affiliates and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. We began allocating administration expenses from the Partnership to our Operating Companies using the Modified Massachusetts Formula Calculation (MMFC) which is based on factors such as respective segments gross margins, employee costs, and property and equipment.

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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:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Costs allocated from ETP to operating subsidiaries:				
Midstream and intrastate transportation and storage operations	$ 15,776	$ 19,834	$ 6,761	$ 11,357
Interstate operations	4,922	5,750	2,613	4,388
Retail propane and other retail propane related operations	12,113	12,664	5,992	10,067
Total	$ 32,811	$ 38,248	$ 15,366	$ 25,812
Costs allocated from operating subsidiaries to ETP:				
Midstream and intrastate transportation and storage operations	$ 6,699	$ 10,649	$ 2,440	$ 5,221
Retail propane and other retail propane related operations	412	2,428	850	2,187
Total	$ 7,111	$ 13,077	$ 3,290	$ 7,408

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The following tables present the financial information by segment for the following periods:

	Years Ended December 31, 2009	2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 1,773,528	$ 3,379,424	$ 929,357	$ 3,085,940
Intersegment revenues	618,016	2,255,180	325,044	829,992
	2,391,544	5,634,604	1,254,401	3,915,932
Interstate transportation - revenues from external customers	270,213	244,224	76,000	178,663
Midstream				
Revenues from external customers	2,060,451	4,029,508	826,835	2,121,289
Intersegment revenues	380,709	1,312,885	339,478	732,207
	2,441,160	5,342,393	1,166,313	2,853,496
Retail propane and other retail propane related - revenues from external customers	1,292,583	1,624,010	511,258	1,284,867
All other:				
Revenues from external customers	20,520	16,702	6,060	121,278
Intersegment revenues	1,145	-	-	-
	21,665	16,702	6,060	121,278
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)
Total revenues	$ 5,417,295	$ 9,293,868	$ 2,349,510	$ 6,792,037
Cost of products sold:				
Intrastate transportation and storage	$ 1,393,295	$ 4,467,552	$ 964,568	$ 3,137,712
Midstream	2,116,279	4,986,495	1,043,191	2,632,187
Retail propane and other retail propane related	596,002	1,038,722	325,158	759,634
All other	16,350	13,376	5,259	110,872
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)
Total cost of products sold	$ 3,122,056	$ 6,938,080	$ 1,673,654	$ 5,078,206
Depreciation and amortization:				
Intrastate transportation and storage	$ 107,605	$ 84,701	$ 20,670	$ 56,145
Interstate transportation	48,297	37,790	12,305	27,972
Midstream	70,845	59,344	13,629	23,388
Retail propane and other retail propane related	83,476	79,717	24,537	70,833
All other	2,580	599	192	824

Total depreciation and amortization	$ 312,803	$ 262,151	$ 71,333	$ 179,162
Operating income (loss):				
Intrastate transportation and storage	$ 626,779	$ 718,348	$ 172,120	$ 488,098
Interstate transportation	138,233	124,676	29,657	95,650
Midstream	140,732	166,414	73,167	123,176
Retail propane and other retail propane related	229,229	114,564	46,747	124,263
All other	(8,658)	(1,531)	(628)	1,735
Selling general and administrative expenses not allocated to segments	1,292	(4,892)	2,571	(3,270)
Total operating income	$ 1,127,607	$ 1,117,579	$ 323,634	$ 829,652
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (394,274)	$ (265,701)	$ (66,298)	$ (175,563)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	(1,013)	31,032
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	2,157	9,306	(5,202)	2,019
Income tax expense	(12,777)	(6,680)	(10,789)	(13,658)
	(336,065)	(251,556)	(61,810)	(152,371)
Net income	$ 791,542	$ 866,023	$ 261,824	$ 677,281

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	As of December 31,			As of August 31,
	2009	2008	2007	2007
Total assets:				
Intrastate transportation and storage	$ 4,901,102	$ 4,642,430	$ 3,976,895	$ 3,534,013
Interstate transportation	3,313,837	2,487,078	1,834,941	1,653,363
Midstream	1,523,538	1,537,972	1,304,187	801,968
Retail propane and other retail propane related	1,784,353	1,810,953	1,778,426	1,593,863
All other	212,142	149,056	113,712	125,221
Total	$ 11,734,972	$ 10,627,489	$ 9,008,161	$ 7,708,428

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):				
Intrastate transportation and storage	$ 378,494	$ 993,886	$ 320,965	$ 827,859
Interstate transportation	99,341	720,186	167,343	1,345,637
Midstream	95,081	267,900	414,722	201,646
Retail propane and other retail propane related	62,953	130,358	47,553	65,125
All other	44,911	3,072	953	2,015
Total	$ 680,780	$ 2,115,402	$ 951,536	$ 2,442,282

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 and variations in the weighted average units outstanding used in computing such amounts. 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 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.

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	Quarter Ended				
2009:	March 31	June 30	September 30	December 31	Total Year
Revenues	$ 1,630,100	$ 1,151,817	$ 1,129,596	$ 1,505,782	$ 5,417,295
Gross profit	670,961	525,824	451,448	647,006	2,295,239
Operating income	360,853	219,220	177,347	370,187	1,127,607
Net income	307,167	150,738	72,456	261,181	791,542
Limited Partners interest in net income	216,877	63,559	(16,471)	162,215	426,180
Basic net income per limited partner unit	$ 1.37	$ 0.38	$ (0.10)	$ 0.92	$ 2.53
Diluted net income per limited partner unit	$ 1.37	$ 0.38	$ (0.10)	$ 0.91	$ 2.53

	Quarter Ended				
2008:	March 31	June 30	September 30	December 31	Total Year
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	$ 1.78	$ 0.61	$ 0.94	$ 0.45	$ 3.74
Diluted net income per limited partner unit	$ 1.77	$ 0.60	$ 0.94	$ 0.45	$ 3.74

For the three months ended September 30, 2009, distributions paid for the period exceeded net income by $177.0 million. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.

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. Certain financial statement amounts have been adjusted due to the adoption of new accounting standards in 2009. See Note 2.

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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 As Adjusted	2006 As Adjusted
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	272,613	164,055
Income tax expense	10,789	3,120
NET INCOME	261,824	160,935
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	-	490
NET INCOME ATTRIBUTABLE TO PARTNERS	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	$ 1.24	$ 0.70
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	137,624,934	123,931,608
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.24	$ 0.70
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	138,013,366	124,229,968

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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	$ 160,935
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)
	4,259	128,554
Comprehensive income	266,083	289,489
Less: Comprehensive income attributable to noncontrolling interest	-	490
Comprehensive income attributable to partners	$ 266,083	$ 288,999

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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	$ 160,935
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
Non-cash unit-based compensation expense	8,114	4,385
Non-cash executive compensation	442	-
Deferred income taxes	1,003	(2,234)
Gain on disposal of assets	(14,310)	(2,212)
Distributions in excess of (less than) equity in earnings of affiliates, net	4,448	(4,743)
Other non-cash	(2,069)	(76)
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	(651,228)	(336,473)
Contributions in aid of construction costs	3,493	4,984
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 INVESTING ACTIVITIES:				
Capital expenditures accrued	$	87,622	$	13,294
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$	3,896	$	532,631
Issuance of common units in connection with certain acquisitions	$	1,400	$	-
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid during the period for interest, net of interest capitalized	$	51,465	$	27,496
Cash paid during the period for income taxes	$	9,009	$	6,196

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that any material information relating to us is accumulated and communicated to our management, including the 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, 2009 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, 2009.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2009, as stated in their report, which is included herein.

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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, 2009, 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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007 and our report dated February 24, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 24, 2010

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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, 2009 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

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. ETE, as the sole member of ETP LLC, is entitled under the limited liability company agreement of ETP LLC to appoint all of the directors of ETP LLC. This agreement provides that the Board of Directors of ETP LLC shall consist of not more than 13 persons, at least three of whom are required to qualify as independent directors. Our 11 current directors include ETP LLC s Chief Executive Officer and ETP LLC s President.

From January 1, 2009 until December 23, 2009, our Board of Directors was comprised of 11 persons, eight of whom qualified as independent under the NYSE s corporate governance standards. Mr. Kenneth A. Hersh was one of the directors that met the NYSE s independence requirements. On December 23, 2009, Mr. Hersh ceased to serve on our Board of Directors, and Marshall S. (Mackie) McCrea, III, was appointed to the Board. Mr. McCrea is our President and Chief Operating Officer and therefore is not considered independent under the NYSE s standards. We have determined that Messrs. Albin, Byrne, Collins, Glaske, Grimm, Harkey and Turner all meet the NYSE s independence requirements.

As a limited partnership, we are not required by the rules of the NYSE to seek unitholder approval for the election of any of our directors. We believe that ETE has appointed as directors individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in natural gas operations or finance, and a history of service in senior leadership positions. We do not have a formal process for identifying director nominees, nor do we have a formal policy regarding consideration of diversity in identifying director nominees, but we believe ETE has endeavored to assemble a group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Board Leadership Structure. We have no policy requiring either that the positions of the Chairman of the Board and the Chief Executive Officer, or CEO, be separate or that they be occupied by the same individual. The Board of Directors believes that this issue is properly addressed as part of the succession planning process and that a determination on this subject should be made when it elects a new chief executive officer or at such other times as when consideration of the matter is warranted by circumstances. Currently, the Board of Directors believes that the CEO is best situated to serve as Chairman because he is the director most familiar with the Partnership s business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. Our independent directors bring experience, oversight and expertise from outside the Partnership and from a variety of industries, while the CEO brings extensive experience and expertise related to the Partnership s business. The Board of Directors believes that the current combined role of Chairman and CEO promotes strategy development and execution, and facilitates information flow between management and the Board of Directors, which are essential to effective governance.

One of the key responsibilities of the Board of Directors is to develop strategic direction and hold management accountable for the execution of strategy once it is developed. The Board of Directors believes the current combined role of Chairman and CEO, together with a majority of independent board members, is in the best interest of Unitholders because it provides the appropriate balance between strategy development and independent oversight of management.

Risk Oversight. Our Board of Directors generally administers its risk oversight function through the board as a whole. Our CEO, who reports to the Board of Directors, and the other executive officers, who report to our CEO, have day-to-day risk management responsibilities. Each of these executives attends the meetings of our Board of

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Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, at each regular meeting of the Board, management provides a report of the Partnership s financial and operational performance, which often prompts questions or feedback from the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership s internal auditor, who reports directly to the Audit Committee, and reviews the Partnership s contingencies with management and our independent auditors.

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 2009, 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.

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 2009. 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 and Mr. Glaske serves as the chairman of 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. Pursuant to the charter of the Compensation Committee, 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 and Mr. Grimm serves as the chairman of the Compensation Committee.

Matters relating to the nomination of directors or corporate governance matters are addressed to and determined by the full Board of Directors.

Code of Business Conduct and Ethics

The Board of Directors has adopted a Code of Business Conduct and Ethics applicable to our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. The Code of Business Conduct and Ethics is available on our website at www.energytransfer.com and in print to any Unitholder that requests it. Amendments to, or waivers from, the Code of Business Conduct and Ethics will also be available on our website and reported as may be required under SEC rules, however, any technical, administrative or other non-substantive amendments to the Code of Business Conduct and Ethics may not be posted. Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. 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.

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Directors and Executive Officers of the General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of February 11, 2010. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	54	Chief Executive Officer and Chairman of the Board of Directors
Marshall S. (Mackie) McCrea , III	50	President, Chief Operating Officer and Director
J. Michael Howard	36	President Midstream
William G. Powers, Jr.	56	President Propane
Martin Salinas, Jr.	38	Chief Financial Officer
Jerry J. Langdon	58	Chief Administrative and Compliance Officer
Thomas P. Mason	53	Vice President, General Counsel and Secretary
Ray C. Davis	68	Director
Bill W. Byrne	80	Director
David R. Albin	50	Director
Paul E. Glaske	76	Director
K. Rick Turner	51	Director
Ted Collins, Jr.	71	Director
John W. McReynolds	59	Director
Michael K. Grimm	55	Director
John D. Harkey, Jr.	49	Director

Messrs. Warren, McCrea, Davis, Byrne, Albin, Glaske, Turner, McReynolds, and Harkey also serve as directors of ETE s general partner.

On December 23, 2009, Kenneth A. Hersh requested he not be considered for re-appointment to the Board of Directors due to time constraints on his other business-related matters, and he ceased to serve on the Board effective on such date.

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

Kelcy L. Warren. Mr. Warren is the Chief Executive Officer and Chairman of the Board of our General Partner and has served in 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 also 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. The Board of Directors selected Mr. Warren to serve as a director and as Chairman because he is the Partnership s Chief Executive Officer and has more than 25 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.

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Marshall S. (Mackie) McCrea, III. Mr. McCrea was appointed as a director on December 23, 2009. He 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. Mr. McCrea also currently serves on the Board of Directors of the General Partner of ETE. The Board of Directors selected Mr. McCrea to serve as a director because he serves as our President and Chief Operating Officer and brings exclusive project development and operational experience to the Board. He has held various positions in the natural gas business over the past 25 years and is able to assist the Board of Directors in creating and executing the Partnership s strategic plan.

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, Jr. 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. 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

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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 became a venture partner of Natural Gas Partners, L.L.C. in September 2007. The Board of Directors selected Mr. Davis to serve as a director based on his more than 32 years of business experience in the energy industry and his expertise in the Partnership s asset portfolio.

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). The Board of Directors selected Mr. Byrne to serve as a director based on his significant industry expertise, as evidenced by his prior position at the 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. The Board of Directors selected Mr. Albin to serve as a director in connection with the investment made by Natural Gas Partners in the Partnership in 2004. Mr. Albin brings his significant industry knowledge, accumulated over the past 20 years by investing in the natural gas sector, to the Board of Directors.

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. The Board selected Mr. Glaske to serve as a director because it believes he is familiar with running a company from the field level to the boardroom based on his previous experience. As a former CEO and director at various other companies, Mr. Glaske has been involved in succession planning, compensation, employee management and the evaluation of acquisition opportunities.

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. The Board of Directors selected Mr. Turner based on his industry knowledge, his background in corporate finance and accounting, and his experience as a director on the boards of several other companies.

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

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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, serves on the Compensation Committee, and is the Chairman of the Governance Committee of Encore Acquisition Company. Mr. Collins has served as a director of our General Partner since August 2004. The Board selected Mr. Collins to serve as a director because of his previous experience as an executive in various positions in the oil and gas industry. As a public company director at various other companies, Mr. Collins has been involved in succession planning, compensation, employee management and the evaluation of acquisition opportunities.

John W. McReynolds. Mr. McReynolds is a director, and the President and Chief Financial Officer of 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. The Board selected Mr. McReynolds to serve as a director because of his legal background and his extensive experience in energy-related corporate finance. Mr. McReynolds has relationships with executive and senior management at several companies in the energy sector, as well as with investment bankers who cover the industry.

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. The Board selected Mr. Grimm to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

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. From 2005 to 2006, Mr. Harkey served on the Board of Directors and Audit Committee of Pizza Inn, Inc. and from 1999 to 2006, he served on the Board of Directors and was Chairman of the Audit Committee of Fox & Hound Restaurant Group (formerly Total Entertainment Restaurant Corp.). 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. The Board selected Mr. Harkey to serve as a director because of his background in corporate finance, as well as his experience as a director on the boards and audit committees of several other public companies.

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 Companies. Our General Partner and its affiliates performing services for the Partnership and the Operating Companies 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 Companies, and thus, our General Partner has not incurred additional reimbursable costs since that time.

Section 16(a) Beneficial Ownership Reporting Compliance

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 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 the year ended December 31, 2009, 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 one transaction by Mr. Powers; and

- late filing of a Form 4 for eleven transactions by Mr. Grimm.

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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 33% of our outstanding units. All of our employees are employed by and receive employee benefits from our subsidiary operating companies.

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;

Marshall S. (Mackie) McCrea, III, President and Chief Operating Officer;

Martin Salinas, Jr., Chief Financial Officer;

Thomas P. Mason, Vice President, General Counsel and Secretary; and

William G. Powers, Jr., President of Propane Operations.

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 (i) 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 (ii) 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. We have previously issued restricted unit awards that vest over a three-year period based on the achievement of annual performance objectives as compared to 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 the importance we place on 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. The compensation committee of the board of directors of our General Partner (the Compensation Committee) is responsible for the approval of the compensation policies and the compensation levels of these executive officers.

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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, 2009, 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 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 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 7 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.

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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, 2009, 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 equity incentive plans;
- 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.

Periodically, the Compensation Committee engages a third-party consultant to assist in the determination of compensation levels for our executive officers. Most recently, 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 a general comparison of the levels of base salary, annual bonus and long-term equity incentives at these other companies with those of our named executive officers in order to assure that compensation of our named executive officers is competitive with the compensation for executive officers of these other companies in the industry. The Compensation Committee did not attempt to benchmark the base salary, annual bonus or long-term equity incentives to any percentage of, or numerical average of, the compensation levels at these other companies. Mercer did not provide any non-executive compensation services for the Partnership during 2008. The Compensation Committee did not engage a compensation consultant in 2009.

Base Salary. As discussed above, the base salaries of our named executive officers are determined by the board of directors of our General Partner based on recommendations from the Compensation Committee, which take

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into account the recommendations of Mr. Warren. The Compensation Committee determined to freeze base salaries for our named executive officers for 2009 at the same levels as for 2008 due to the uncertainties related to the economy and the natural gas markets.

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 year 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. EBITDA guidance is generally determined based on the Partnership s internal financial budget, which is reviewed and approved by the Board of Directors of our General Partner as discussed below. 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.

For the year ended December 31, 2008, 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. The budgets for 2008 were presented to the Board of Directors of our General Partner for review and approval prior to the beginning of the year. The Partnership s 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 considering 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.

The Compensation Committee has not made any determinations with respect to cash bonuses for the named executive officers for the year ended December 31, 2009.

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 and Mason previously received unit awards under our equity incentive plans, a portion of which vested during 2009.

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, 2009, 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 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 2009, 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, 2009 became vested and 75% of the awards were forfeited based on our performance for the twelve-month period ended August 31, 2009.

Commencing in 2008, all of the new unit awards granted have provided for vesting over a specified time period, with vesting based on continued employment as of each applicable vesting date, rather than vesting based on the satisfaction of any performance objectives as the Compensation Committee determined that vesting based on continued employment, rather than the satisfaction of performance objectives, was more generally prevalent with companies in the energy industry with which we compete for talented employees. In December 2008, the Compensation Committee approved the grant of 644,545 new unit awards under our 2004 Unit Plan and our 2008 Incentive Plan to approximately 275 employees, including certain of our named executive officers. In December 2009, 716,700 new unit awards under our equity incentive plans were granted to approximately 340 employees. This grant was approved by the Compensation Committee. 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, Mason and Powers received grants in December 2009 relating to 20,000, 19,186, 18,186 and 10,000 ETP Common Units, respectively and received grants in December 2008 relating to 20,000, 20,000, 20,000 and 10,000 ETP Common Units, respectively. Messrs. Mason and Powers also received grants relating to 50,000 and 20,000 ETP Common Units in October 2008 and February 2008, 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, 2009, the Compensation Committee accelerated the vesting of 41,931 unit awards in connection with the termination of certain employees.

Affiliate Equity Awards. McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of ETE s General Partner, has awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officers. These rights include the economic benefits of

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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. 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.

Messrs. McCrea, Salinas and Mason vested in rights related to ETE units of 42,000, 48,000 and 55,000, respectively, during 2009 and had unvested rights related to ETE units of 168,000, 192,000 and 110,000, respectively, as of December 31, 2009.

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 18 years of age (age 21 for certain union workers) are eligible to participate. Employees may elect to defer up to 100% of defined eligible compensation after applicable taxes, as limited under the Internal Revenue Code. We shall make a matching contribution that satisfies the requirements of Section 401(k)(12)(B) and 401(m)(11) of the Internal Revenue Code. The rate of match shall not be less than the aggregate amount of matching contributions that would be credited to a participant s account based on a rate of match equal to 100% of each participant s elective deferrals up to 5% of covered compensation. The entire amount credited to the participant s account shall be fully vested and non-forfeitable at all times. Prior to 2009, our 401(k) plan matching contributions were discretionary, based on a percentage of compensation, and participants vested in matching contributions upon completion of one year of service. Prior to 2009, our 401(k) plan also required the attainment of age 21 for all employees.

Health and Welfare Benefits. All full-time employees, including our executive officers, may participate in our health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance 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 (as defined therein) of ETE); or (iv) a liquidation or dissolution of ETP. No such accelerated vesting occurred during the year ended December 31, 2009. The value of unvested unit awards that would fully vest upon a change of control as defined in our equity incentive plans was $2,212,524 for Mr. McCrea, $1,744,206 for Mr. Salinas, $3,821,820 for Mr. Mason, and $1,690,872 for Mr. Powers based on the closing unit price per ETP Common Unit on December 31, 2009. The value of unvested affiliate equity awards that would fully vest upon a change of control as defined in the affiliate equity awards was $5,137,440 for Mr. McCrea, $5,871,360 for Mr. Salinas and $3,363,800 for Mr. Mason, based on the closing unit price per ETE Common Unit on December 31, 2009.

Deferred Compensation Arrangements. We did not have any deferred compensation arrangements or defined benefit pension plans or other post retirement benefits for our named executive officers during 2009 or prior.

Risk Assessment Related to our Compensation Structure. We believe our compensation plans and programs for executive officers, as well as other employees, are appropriately structured and are not reasonably likely to result in material risk to the Partnership. We believe our compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm our value or reward poor judgment. We also

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believe we have allocated our compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for the executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment. We generally determine whether, and to what extent, our executive officers and our other employees receive a cash bonus based on our achievement of specified financial performance objectives. For example, in 2007 we announced EBITDA guidance for 2008 that we believed was reasonable in light of past performance and market conditions, and our Compensation Committee took into account whether the Partnership met or exceeded that public guidance for the purpose of determining cash bonuses for our executive officers following the completion of the 2008 calendar year. As described above, in 2008, we stopped issuing performance-based awards in favor of time-based vesting awards that generally vest over a five-year period. We use restricted units rather than unit options for equity awards because restricted units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options in-the-money. Finally, the time-based vesting over five years for our long-term incentive awards ensures that our employees interests align with those of our Unitholders for the long-term performance of the Partnership.

Director Compensation

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. In 2009, 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. In addition, the non-employee directors participate in our 2004 Unit Plan and 2008 Incentive 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, who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of 2,500 ETP Common Units. Under our 2004 Unit Plan and 2008 Incentive Plan, the non-employee directors of our General Partner each receive annual grants of unvested ETP Common Units equal to an aggregate of $50,000 divided by the fair market value of our Common Units. These ETP Common Units vest over three years at one-third per year. Annual Director Grants of 10,640 units were awarded during 2009. Director grants that vested in 2009 resulted in the issuance of 3,530 ETP Common Units.

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

For our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 8 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm, Byrne and Davis served on the Compensation Committee during 2009. During 2009, 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

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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.

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Compensation Tables

Summary Compensation Table

Name and Principal Position	Year (1)	Salary ($)	Bonus ($) (2)	Equity Awards ($) (3)	Option Awards ($)	Non-equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (4)	Total ($)
Kelcy L. Warren (5)	2009	$ 2,289	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,289
Chief Executive Officer	2008	2,272	-	-	-	-	-	-	2,272
	Transition	220,429	-	-	-	-	-	4,846	225,275
	2007	500,000	-	406,490	-	-	-	14,000	920,490
Marshall S. (Mackie) McCrea, III	2009	500,000	-	883,000	-	-	-	12,250	1,395,250
President and Chief	2008	444,154	750,000	825,678	-	-	-	3,427,408	5,447,240
	Transition	177,926	200,000	1,313,861	-	-	-	5,327	1,697,114
Operating Officer	2007	380,769	600,000	298,106	-	-	-	14,481	1,293,356
Martin Salinas, Jr. (6)	2009	350,000	-	847,062	-	-	-	31,293	1,228,355
Chief Financial Officer	2008	261,539	550,000	727,265	-	-	-	6,922,369	8,461,173
Thomas P. Mason (7)	2009	420,240	-	802,912	-	-	-	41,005	1,264,157
Vice President, General Counsel and	2008	410,410	630,000	2,332,800	-	-	-	32,347	3,405,557
Secretary	Transition	130,769	167,000	746,985				6,462	1,051,216
	2007	238,462	291,667	-	-	-	-	8,800,000	9,330,129
William G. Powers, Jr. (8)	2009	407,692	500,000	441,500	-	-	-	22,000	1,371,192
President of Propane Operations	2008	336,925	300,000	1,353,827	-	-	-	20,488	2,011,240

(1) Amounts presented for 2009 and 2008 are based on the calendar year of January 1 to December 31, 2009 and 2008, respectively. 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 discretionary cash bonus amounts, if any, for our named executive officers to be paid for 2009 have not yet been determined, except where indicated. The annual bonuses for 2009 for Messrs. McCrea, Salinas and Mason are subject to determination by the Compensation Committee, which is expected to occur in March 2010. The bonus amounts presented above represent the discretionary cash bonus earned with respect to the period presented, which amounts were actually paid in the following period.

(3) Equity award amounts reflect the aggregate grant date fair value of unit awards granted during the periods presented. 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.

(4) The amounts in this column include (a) the aggregate grant date fair value related to grants of equity-based awards of units in ETE owned by an affiliate to certain of our named executive officers during the periods presented, as discussed further above and in Note 8 to our consolidated financial statements, and (b) contributions to the 401(k) plan made by ETP on behalf of the named executive officers.

(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 2008. The 2008 amounts reflect his compensation for the entire year.

(7) Mr. Mason began employment in February 2007. Thus, the fiscal year 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.

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(8) Mr. Powers was promoted to President of Propane Operations in May 2008. The 2008 amounts reflect his compensation for the entire year.

All Other Compensation Table

Name	Year (1)	Perquisites and Other Personal Benefits ($)(2)	Tax Reimbursements ($)	Life Insurance Premiums ($) (3)	Company Contributions to Retirement and 401(k) Plans ($) (4)	Severance Payments / Accruals ($)	Change in Control Payments / Accruals ($) (5)	Affiliate Equity Awards ($) (6)	Total ($)
Kelcy L. Warren	2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2008	-	-	-	-	-	-	-	-
	Transition	-	-	-	4,846	-	-	-	4,846
	2007	-	-	-	14,000	-	-	-	14,000
Marshall S. (Mackie) McCrea, III	2009	-	-	-	12,250	-	-	-	12,250
	2008	-	-	-	14,908	-	-	3,412,500	3,427,408
	Transition	-	-	-	5,327	-	-	-	5,327
	2007	-	-	-	14,481	-	-	-	14,481
Martin Salinas, Jr.	2009	19,043	-	-	12,250	-	-	-	31,293
	2008	-	-	-	12,769	-	-	6,909,600	6,922,369
Thomas P. Mason	2009	28,755	-	-	12,250	-	-	-	41,005
	2008	26,867	-	-	5,480	-	-	-	32,347
	Transition	-	-	-	6,462	-	-	-	6,462
	2007	-	-	-	-	-	-	8,800,000	8,800,000
William G. Powers, Jr.	2009	-	-	-	22,000	-	-	-	22,000
	2008	-	-	-	20,488	-	-	-	20,488

(1) Amounts presented for 2009 and 2008 are based on the calendar year of January 1 to December 31, 2009 and 2008, respectively. 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) Perquisites include expenses paid by us for housing near our executive office in Dallas for certain executives who commute from other cities.

(3) 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.

(4) 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.

(5) Amounts presented do 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 amounts are reflected in the Outstanding Equity Awards at Year-End Table below.

Amounts presented do not include the value of unvested affiliate equity awards granted to Messrs. McCrea, Salinas and Mason, that would fully vest upon a change of control as defined in the affiliate equity awards, which value was $5,137,440 for Mr. McCrea, $5,871,360 for Mr. Salinas, and $3,363,800 for Mr. Mason, based on the December 31, 2009 closing unit price per ETE Common Unit.

(6) Affiliate equity awards reflect the aggregate grant date fair value related to equity-based awards of units in ETE owned by an affiliate to certain of our named executive officers during the periods presented, as discussed in Note 8 to our consolidated financial statements.

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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 (1)
Kelcy L. Warren	N/A	-	-	-	-	-	$ -	$ -
Marshall S. (Mackie) McCrea, III	12/15/09	-	-	-	20,000	-	-	883,000
Martin Salinas, Jr.	12/15/09	-	-	-	19,186	-	-	847,062
Thomas P. Mason	12/15/09	-	-	-	18,186	-	-	802,912
William G. Powers, Jr.	12/15/09	-	-	-	10,000	-	-	441,500

(1) We have computed the grant-date fair value of unit awards in accordance with generally accepted accounting principles, as further described above and in Note 8 to our consolidated financial statements.

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 our equity incentive plans and such awards are in the sole discretion of Mr. McReynolds. The grant date fair value of these awards is detailed above in the All Other Compensation Table and related footnotes.

Outstanding Equity Awards at Year-End Table

Name	Grant Date (1)	Stock Awards: Number of Units That Have Not Vested (#) (2)	Market Value of Units That Have Not Vested ($) (2)	Equity Incentive Plan Awards: Number of Units That Have Not Vested (#) (1)	Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested ($) (3)
Kelcy L. Warren	N/A	-	$ -	-	$ -
Marshall S. (Mackie) McCrea, III	12/15/09	-	-	20,000	899,400
	12/22/08	-	-	16,000	719,520
	12/05/07	-	-	13,200	593,604
Martin Salinas, Jr.	12/15/09	-	-	19,186	862,794
	12/22/08	-	-	16,000	719,520
	12/05/07	-	-	3,600	161,892
Thomas P. Mason	12/15/09	-	-	18,186	817,824
	12/22/08	-	-	16,000	719,520
	10/17/08	-	-	40,000	1,798,800
	12/05/07			10,800	485,676

William G. Powers, Jr.	12/15/09	-	-	10,000	449,700
	12/22/08	-	-	8,000	359,760
	02/28/08	-	-	16,000	719,520
	12/05/07	-	-	3,600	161,892

(1) Unit awards outstanding as of December 31, 2009 reflected in the table above ratably vest on each anniversary of the grant date through 2014 for awards granted in 2009, through 2013 for awards granted in 2008, and through 2012 for awards granted in 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) Market value was computed as the number of unvested awards at December 31, 2009 multiplied by our Common Unit closing per unit market price at December 31, 2009.

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Option Exercises and Units Vested Table

	Unit Awards	
Name	Number of Units Acquired on Vesting (#) (1)	Value Realized on Vesting ($) (1)
Kelcy L. Warren	1,250	$ 54,763
Marshall S. (Mackie) McCrea, III	9,317	399,986
Martin Salinas, Jr.	5,534	240,189
Thomas P. Mason	17,600	760,860
William G. Powers, Jr.	7,700	306,393

(1) Amounts presented represent the number of unit awards vested during 2009 and the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the closing price of our Common Units upon the vesting date.

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 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.

The compensation paid to the non-employee directors of our General Partner is reflected in the following table.

Director Compensation Table

Name	Fees Paid in Cash ($) (1)	Unit Awards ($) (2)	All Other Compensation ($)	Total ($)
Ray C. Davis	49,800	51,185	-	100,985
Bill W. Byrne	81,400	51,185	-	132,585
David R. Albin	-	-	-	-
Paul E. Glaske	77,800	51,185	-	128,985
K. Rick Turner	40,000	51,185	-	91,185
Ted Collins, Jr.	40,000	51,185	-	91,185
Michael K. Grimm	52,300	51,185	-	103,485
John D. Harkey, Jr.	71,600	51,185	-	122,785
Kenneth A. Hersh (3)	-	-	-	-

(1) Fees paid in cash are based on amounts paid during the period.

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price of ETP Common Units as of the grant date, reduced by the present value of the expected distributions during the vesting period.

(3) Mr. Hersh ceased to serve on our Board of Directors in December 2009.

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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 equity incentive plans as of December 31, 2009:

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	1,690,592	$ -	4,218,689
Equity compensation plans not approved by security holders	-	-	-
Total	1,690,592	$ -	4,218,689

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Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 22, 2010, 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)(3)	Percent of Class
Common Units	Kelcy L. Warren	21,107	*
	Martin Salinas, Jr.	12,568	*
	Marshall S. (Mackie) McCrea, III	44,500	*
	Jerry J. Langdon	5,296	*
	Thomas P. Mason	15,024	*
	Ray C. Davis	53,820	*
	Bill W. Byrne	162,776	*
	David R. Albin	10	*
	Kenneth A. Hersh (4)	10	*
	Paul E. Glaske	82,545	*
	Michael K. Grimm	20,198	*
	John D. Harkey, Jr.	3,060	*
	K. Rick Turner (5)	7,601	*
	Ted Collins, Jr.	100,802	*
	John W. McReynolds	17,987	*
	All Directors and Named Executive as a Group (15 persons)	547,304	*
	ETE (6)	62,500,797	33.03%
Class E Units	Heritage Holdings, Inc.(7)	8,853,832	100%

* Less than 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 certain officers and directors of the general partner of ETE of equity interests in ETE (either directly or through one or more entities) and due to their positions as directors of the general partner of ETE, they may be deemed to beneficially own the ETP limited partnership interests held by ETE, to the extent of their respective interests therein. Any such

deemed ownership is not reflected in the table.

(4) Mr. Hersh ceased to serve on our Board of Directors in December 2009.

(5) Mr. Turner is a representative of or owner in an entity owning interests in ETE and may be deemed to beneficially own the limited partnership interest held by ETE. Any such deemed ownership is not depicted in the table.

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(6) ETE owns all 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.

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

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS,

AND DIRECTOR INDEPENDENCE

As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The partnership agreement of the Partnership provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all the 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.

On December 23, 2009, Dan L. Duncan and Ralph S. Cunningham were appointed as directors of LE GP, LLC, the general partner of ETE. Mr. Duncan is Chairman and a director of EPE Holdings, LLC, the general partner of Enterprise GP; Chairman and a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., or EPD; and Group Co-Chairman of EPCO, Inc. TEPPCO Partners, L.P., or TEPPCO, is also an affiliate of EPE. Dr. Cunningham is the President and Chief Executive Officer of EPE Holdings, LLC, the general partner of Enterprise GP. These entities and other affiliates of Enterprise and Enterprise GP are referred to herein collectively as the Enterprise Entities. Mr. Duncan directly or indirectly beneficially owns various interests in the Enterprise Entities, including various general partner interests and approximately 77.1% of the common units of Enterprise GP, and approximately 34% of the common units of EPD. On October 26, 2009, TEPPCO became a wholly owned subsidiary of Enterprise. See discussion of our transactions with Enterprise in Note 14 to our consolidated financial statements.

Effective August 17, 2009, we acquired 100% of the membership interests of Energy Transfer Group, L.L.C. (ETG), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. (ETT). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. 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 ETG. In addition, two of our directors, Ted Collins, Jr. and John W. McReynolds, served on ETG s board of directors. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of our General Partner s general partner and the other of which is controlled by a member of ETP s management. In exchange, the former members acquired the right to receive (in cash or Common Units), future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG will receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million. Our acquisition of ETG was approved by the Conflicts Committee.

See discussion of transactions with ETG and ETT in Note 14 to our consolidated financial statements. The terms of each arrangement to provide compression services were negotiated at an arms-length basis by management and were reviewed and approved by the Audit Committee.

Under the terms of a Shared Services Agreement entered into in connection with the Energy Transfer Transactions, ETG and ETT leased office space and obtained related services from us prior to the acquisition. Fees recognized under this agreement were nominal.

Under the terms of a shared services agreement, ETE pays us an annual administrative fee of $0.5 million for the provision of various general and administrative services. The administrative fee may increase in future periods.

ETE owns directly and indirectly the General Partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights and 62,500,797 ETP Common Units.

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ITEM 14. PRINCIPAL ACCOUNTING 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:

	Years Ended December 31,	
	2009	2008
Audit fees (1)	$ 2,421,000	$ 3,490,000
Audit related fees (2)	-	60,000
Tax fees	-	-
All other fees	-	-
Total	$ 2,421,000	$ 3,550,000

(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.

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 years; and

the rotation of the lead partner.

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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 98.

(2) Financial Statement Schedules - None.

(3) Exhibits - see Index to Exhibits set forth on page E-1.

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SIGNATURES

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

ENERGY TRANSFER 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 24, 2010
/s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer (Principal Financial and Accounting Officer)	February 24, 2010
/s/ Ray C. Davis Ray C. Davis	Director	February 24, 2010
/s/ Bill W. Byrne Bill W. Byrne	Director	February 24, 2010
/s/ David R. Albin David R. Albin	Director	February 24, 2010

/s/ Marshall S. McCrea, III	President, Chief Operating Officer	February 24, 2010
Marshall S. McCrea, III	and Director	
/s/ Paul E. Glaske	Director	February 24, 2010
Paul E. Glaske		
/s/ K. Rick Turner	Director	February 24, 2010
K. Rick Turner		
/s/ Ted Collins, Jr.	Director	February 24, 2010
Ted Collins, Jr.		
/s/ John W. McReynolds	Director	February 24, 2010
John W. McReynolds		
/s/ Michael K Grimm	Director	February 24, 2010
Michael K. Grimm		
/s/ John D. Harkey, Jr.	Director	February 24, 2010
John D. Harkey, Jr.		

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INDEX TO EXHIBITS

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

f September 22, 2008 by and among Energy Transfer Partners, L.P. and OGE Energy Corp.

eement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009.

of Heritage Operating, L.P.

Restated Agreement of Limited Partnership of Heritage Operating, L.P.

Restated Agreement of Limited Partnership of Heritage Operating, L.P.

Restated Agreement of Limited Partnership of Heritage Operating, L.P.

rtnership of Energy Transfer Partners, L.P.

rtnership of Heritage Operating, L.P.

ement of Limited Partnership of Energy Transfer Partners GP, L.P.

ed Liability Agreement of Energy Transfer Partners, L.L.C.

Limited Partner Interests of Heritage Propane Partners, L.P.

January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.

mong Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.

January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors names therein and Wachovia Bank, National Association, as trustee.

ed 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 B

l 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, Nation

Transfer Partners, L.P.

Energy Transfer Partners, L.P.

ed 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, Natio

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, Nat

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rustee.

r, 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 Ci

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ement and August 10, 2000 Note Purchase Agreement.

ment and August 10, 2000 Note Purchase Agreement.

ers and La Grange Acquisition, L.P., as Buyer.

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 Co

l Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.

Banks now or hereafter signatory parties hereto, as lenders Banks and Bank of Oklahoma, National Association as administrative agent and joint lead arranger fo

asers parties thereto.

istrative agent, and certain other lenders party thereto.

as the administrative agent.

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scription

aranty Agreement, dated as of November 13, 2009, between Energy Transfer Partners, L.P., as the guarantor, and The Royal Bank of Scotland plc, as the administrati

t of Subsidiaries.

nsent of Grant Thornton LLP.

tification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

tification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

tification 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.

tification 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.

ancial Statements of Energy Transfer Partners GP, L.P. as of December 31, 2009

ancial Statements of Energy Transfer Partners, L.L.C. as of December 31, 2009

* Filed herewith.

** Furnished herewith.

\+ Denotes a management contract or compensatory plan or arrangement.

(1) Incorporated by reference the same numbered Registrant s Registration Statement on Form S-1/A, 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.

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(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 8-K filed July 28, 2009.

(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K/A filed September 26, 2008.

(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 4.2 of the Registrant s Form 8-K filed on April 4, 2009.

(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 10.1 to the Registrant s Form 8-K filed December 14, 2009.

(28) Incorporated by reference to Exhibit 10.45 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.

(32) Incorporated by reference to the same numbered Exhibit to the Registrant s Form S-3 filed August 9, 2006.

(33) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed October 25, 2006.

(35) Incorporated by reference to Exhibit 3.1.10 to the Registrant s Form 8-K filed November 3, 2006.

(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.

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(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 July 23, 2007.

(48) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed December 23, 2008.

(49) Incorporated by reference to Exhibit A to the Proxy Statement filed by the Registrant November 21, 2008.

(51) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed March 31, 2008.

(52) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed March 4, 2008.

(53) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed March 4, 2008.

(54) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed November 19, 2009.

(55) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed November 19, 2009.