Energy Transfer Partners, L.P.
Form 10-K
February 22, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

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) (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 ý 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 ý

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 ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 ý 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 ý 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 ý

The aggregate market value as of June 30, 2011, of the registrant's Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was $7.70 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 15, 2012, the registrant had 226,316,387 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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PART I

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (“Energy Transfer Partners” or the “Partnership”) in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include “forward-looking” statements. 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,” “esti “goal,” “forecast,” “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its general partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections 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, the Partnership’s actual results may vary materially from those anticipated, projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Item 1A. Risk Factors” included in this annual report.

Definitions

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

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy content
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
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

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership.

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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 $11.16 billion as of January 31, 2012). We are managed by our general partner, Energy Transfer Partners GP, L.P. (our “General Partner” or “ETP GP”), and ETP GP is managed by its general partner, Energy Transfer Partners, L.L.C. (“ETP LLC”), which is owned by Energy Transfer Equity, L.P., another publicly traded master limited partnership (“ETE”). 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, including the following:
  - 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”); and
  - interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC (“ET Interstate”). ET Interstate is the parent company of Transwestern Pipeline Company, LLC (“Transwestern”), ETC Fayetteville Express Pipeline, LLC (“ETC FEP”) and ETC Tiger Pipeline, LLC (“ETC Tiger”).
- NGL transportation, storage and fractionation services primarily through Lone Star NGL LLC (“Lone Star”).
- Retail propane through Heritage Operating, L.P. (“HOLP”) and Titan Energy Partners, L.P. (“Titan”), both of which were contributed to AmeriGas Partners, L.P. ("AmeriGas") in January 2012 as discussed in "Recent Developments and Current Growth Projects" below.
- Other operations, including natural gas compression services.

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The following chart summarizes our organizational structure as of December 31, 2011:

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 2011 and Beyond

Our significant 2011 achievements included the following, as discussed in more detail herein:

- Formed ETP-Regency Midstream Holdings, LLC (“ETP-Regency LLC”), a joint venture owned 70% by us and 30% by Regency Energy Partners LP (“Regency”), which acquired all of the membership interest in LDH Energy Asset Holdings LLC (“LDH”), a wholly owned subsidiary of Louis Dreyfus Highbridge Energy, for approximately $1.98 billion in cash (the "LDH Acquisition"). We contributed approximately $1.38 billion to ETP-Regency LLC to fund our 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star NGL LLC.
- Completed construction of the 400 MMcf/d expansion of our Tiger pipeline ahead of schedule. The Tiger pipeline expansion was placed in service on August 1, 2011, bringing the total capacity of the Tiger pipeline to 2.4 Bcf/d.
- Issued an aggregate of 31,811,893 Common Units for total net proceeds of $1.47 billion primarily to fund acquisitions, internal growth projects and capital contributions to joint ventures and to manage our investment grade metrics.
- Issued $1.5 billion of senior notes in May 2011 to repay borrowings on our revolving credit facility.

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- Amended our revolving credit facility to increase the capacity from $2.0 billion to $2.5 billion and extend the maturity date to 2016.
- Announced our pending Citrus Acquisition, which is discussed in "Resent Developments and Current Growth Projects" below.
- Announced growth projects aggregating $3.5 billion, including growth projects announced in 2012, which are expected to be placed in service through 2014.

To date in 2012, we have achieved the following:

- Issued $2.0 billion of senior notes in January 2012, the proceeds from which we anticipate using to fund the cash portion of the Citrus Acquisition, which is discussed in "Recent Developments and Current Growth Projects" below, and for general partnership purposes.
- Completed the repurchase of approximately $750 million of our senior notes.
- Completed the contribution of our retail propane businesses to AmeriGas as discussed below.

Recent Developments and Current Growth Projects

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the “Propane Business”), to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas common units in consideration for the contribution of the Propane Business, plus the assumption by AmeriGas of approximately $71 million of existing HOLP debt. This transaction improved our liquidity and allows us to focus on our core businesses in the natural gas and NGL markets. As a result of this transaction, we have not included a discussion of the assets or operations of the Propane Business in Item 1.

Red River Gathering Pipeline

In October 2011, we entered into a long-term, fee-based agreement with XTO Energy, a subsidiary of ExxonMobil, to provide natural gas gathering, processing and transportation services from both the Woodford and Barnett Shale regions. We will construct a 117-mile, 24- and 30-inch natural gas gathering pipeline from the Woodford Shale to our existing gathering and processing infrastructure in the Barnett Shale. The pipeline will have an initial capacity of 450 MMcf/d, with anticipated capacity expansion exceeding 550 MMcf/d. The pipeline is expected to be in service by the fourth quarter of 2012. As part of the pipeline project, we will also construct a new 200 MMcf/d cryogenic processing plant at our existing Godley processing facility in Johnson County, Texas. The new processing plant will increase our processing capacity at Godley from 500 MMcf/d to 700 MMcf/d and is expected to be in service by the third quarter of 2013. The total cost to build the pipeline and processing plant is estimated to be approximately $350 million to $375 million.

Citrus Acquisition

In July 2011, we entered into an Amended and Restated Agreement and Plan of Merger with ETE (the "Citrus Merger Agreement") pursuant to which it is anticipated that Southern Union Company, a Delaware corporation (“SUG”), will cause the contribution to us of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission (“FGT”) pipeline system, in exchange for approximately $1.895 billion in cash and $105 million of our Common Units (the "Citrus Acquisition"), contemporaneous with the completion of the merger between SUG and ETE pursuant to the Second Amended and Restated Agreement and Plan of Merger between ETE and SUG (the "SUG Merger Agreement") as described in Note 3 to our consolidated financial statements included in this report. In order to increase the expected accretion to be derived from the Citrus Acquisition, ETE has agreed to relinquish its rights to approximately $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters following the closing of the transaction. Citrus Corp. is currently jointly owned by SUG and El Paso Corporation. The FGT pipeline system has a capacity of 3.0 Bcf/d. FGT’s primary customers are utilities with strong investment grade credit ratings; FGT’s long-term contracts with these high credit quality customers are expected to increase our fee-based revenue stream.

In connection with the Citrus Merger Agreement, ETE has granted us a right of first offer with respect to any disposition by ETE or SUG of Southern Union Gas Services, a subsidiary of SUG that owns and operates a natural gas gathering and processing system serving the Permian Basin in West Texas and New Mexico.

Lone Star's West Texas Gateway Pipeline

In June 2011, Lone Star announced the construction of a NGL pipeline ("West Texas Gateway Pipeline") that extends from Winkler County in west Texas to our processing plant in Jackson County, Texas, which is currently under construction. Approximately

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60% of the expected pipeline capacity is currently committed under long-term fee-based contracts. Currently, this project is expected to be completed as an approximately 570-mile NGL pipeline with total estimated costs of $917 million, which will be funded by contributions from us and Regency based on our respective ownership interests. In addition, Lone Star has secured capacity on our recently-announced NGL pipeline from Jackson County to Mont Belvieu, Texas.

Lone Star's Mont Belvieu Fractionation Facility

In May 2011, we announced that Lone Star will construct a 100,000 Bbls/d NGL fractionation facility at Mont Belvieu, Texas. We will utilize a substantial amount of this fractionation capacity to handle NGL barrels we will deliver from the new processing facility we plan to build in Jackson County, Texas, a facility supported by multiple 10-year contracts with producers as part of our Eagle Ford Shale projects. Please read “Expansion of Eagle Ford Shale Projects” below. Additionally, Regency plans to provide NGL barrels to this facility for fractionation. As part of this project, Lone Star is developing additional storage facilities for NGLs and other liquids. The project will also include interconnectivity infrastructure to provide NGL suppliers with significant access to storage, other fractionators, pipelines and multiple markets along the Texas and Louisiana Gulf Coast. Total cost of this project is expected to be between $375 million and $400 million and is expected to be completed in the first quarter of 2013.

In February 2012, Lone Star announced the construction of a second 100,000 Bbls/d fractionation facility at Mont Belvieu , Texas. Supported by multiple long-term contracts, the second fractionator is necessary to handle the increasing NGL barrels delivered via the partnership's Woodford Shale, Eagle Ford Shale and Permian Basin infrastructure, including Lone Star's 570-mile West Texas Gateway NGL Pipeline. This second fractionation facility is expected to be completed in the first quarter of 2014 at an estimated cost of $350 million.

Expansion of Eagle Ford Shale Projects

In April 2011, we announced that we had entered into long-term fee-based agreements with multiple producers, including Rosetta Resources Operating LP, SM Energy Company, and a subsidiary of Anadarko Petroleum Corporation, to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale. To facilitate these agreements, which include volume commitments in excess of 540,000 MMBtu/d of natural gas, we will expand the previously announced REM pipeline in south Texas and will construct a new processing facility in Jackson County, Texas. The REM pipeline expansion, which will extend from our Chisholm Pipeline in DeWitt County east into Jackson County, Texas, will add approximately 70 miles of 42-inch pipe to the initial 160-mile, 30-inch pipeline that was announced in February 2011. We completed the initial phase of REM in October 2011 and completion of the REM expansion is scheduled for the fourth quarter of 2012. The first phase of the Jackson County gas processing plant is scheduled for completion in the first quarter of 2013.

In May 2011, we announced that we were considering alternatives to secure NGL pipeline capacity from Jackson County, Texas to Mont Belvieu. Subsequently, we decided to construct a 130-mile, 20-inch NGL pipeline from the new processing facility we plan to build in Jackson County to Mont Belvieu. This pipeline would provide capacity for NGL barrels from the Eagle Ford Shale and from Lone Star's West Texas Gateway Pipeline from west Texas. The capacity of the proposed 20-inch pipeline is expected to be approximately 340,000 Bbls/d and is expected to be completed by the third quarter of 2013.

In February 2012, we announced our entry into multiple long-term, fee-based agreements with producers to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale in south Texas. To facilitate the agreements, we will further expand the REM pipeline and construct a new processing facility at an expected cost of $210 million. The pipeline expansion announced in February 2012 is expected to be completed in the fourth quarter of 2013, and the processing facility announced in February 2012 is are expected to be completed in the fourth quarter of 2012. When fully constructed, the REM pipeline will consist of approximately 257 miles of large diameter pipe with a capacity of at least 1 Bcf/d.

Segment Overview

Our segments and business are as described below. See Note 12 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 8,300 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 to major markets from various prolific 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 we refer to as ET Fuel System, and our HPL System, which are described below.

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Our intrastate transportation and storage segment's 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) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

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 our 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 primarily purchased at a discount to a specified market price and typically 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. The major customers on our intrastate pipelines include Natural Gas Exchange, Inc., EDF Trading North America, Inc., XTO Energy, Inc. and ConocoPhillips.

Interstate Transportation Segment

Through our interstate transportation segment, we own and operate approximately 2,880 miles of interstate natural gas pipeline and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline.

The results from our interstate transportation segment are primarily derived from the fees we earn from natural gas transportation services and, for the Transwestern pipeline, from operational gas sales. The major customers on our interstate pipelines include Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. ("EnCana"), Shell Energy North America (US), L.P. and Pacific Summit Energy LLC.

Midstream Segment

Through our midstream segment, we own and operate approximately 7,400 miles of in service natural gas gathering pipelines, two natural gas processing plants, 15 natural gas treating facilities and 11 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 major producing basins and shales, including the Austin Chalk trend and Eagle Ford Shale in South and Southeast Texas, the Permian Basin in West Texas and New Mexico, the Barnett Shale in North Texas, the Bossier Sands in East Texas, the Uinta and Piceance Basins in Utah and Colorado, the Marcellus Shale in West Virginia, and the Haynesville Shale in East Texas and Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment results are derived primarily from margins we earn for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems and the natural gas and NGL volumes processed at our processing and treating 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. The major customers on our midstream pipelines include Enterprise Products Partners L.P. ("Enterprise") and Chevron Phillips Chemical Company LP.

NGL Transportation and Services Segment

Through our NGL transportation and services segment we own and operate an approximately 45-mile NGL pipeline and have a 50% interest in the Liberty pipeline, an approximately 85-mile NGL pipeline. We also have a 70% interest in the Lone Star joint venture that owns approximately 1,400 miles of NGL pipelines, three NGL processing plants, one fractionation facility and NGL storage facilities with aggregate working storage capacity of 47 million Bbls.

NGL transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL products that are commingled in a storage cavern with other customers' products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns.

This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an Olefins-grade ("O-grade") stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percent-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percent-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee. The major customers on our NGL pipelines include Targa Resources Partners LP, The Williams Companies, Inc. and Louis Dreyfus Highbridge Energy LLC.

Retail Propane Segment

As of December 31, 2011, we owned one of the three largest retail propane marketers in the United States based on gallons sold and served more than one million customers through a nationwide retail distribution network consisting of approximately 440 customer service locations in approximately 40 states. The propane operations extended from coast to coast with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States.

As discussed above, in January 2012 we contributed our propane operations to AmeriGas. See further discussion of this transaction in "Recent Developments and Current Growth Projects" above.

All Other

Segments below the quantitative thresholds are classified as "other." 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.

The following assets are held in connection with our other natural gas operations:

- We own 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 our other segments.
- We also own 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.

Asset Overview

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 2,950 miles of natural gas pipeline
- Two storage facilities with 12.4 Bcf of total working gas capacity
- Bi-directional capabilities

The ET Fuel System serves some of the most active drilling areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. With approximately 560 receipt and/or delivery points, including interconnects with pipelines providing direct access to power plants and interconnects with other intrastate and interstate pipelines, the ET Fuel System is strategically located near high-growth production areas and provides access to the Waha Hub near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas. The major shippers on our pipelines include EOG Resources, Inc., Chesapeake Energy Marketing, Inc., XTO Energy, Inc. ("XTO"), Luminant Energy Company LLC, and EnCana.

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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 that expire in 2012 and 2013.

In addition, the ET Fuel System is integrated with our Godley processing 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 natural gas pipeline. It has bi-directional capability with approximately 1.2 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis pipeline has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

The Oasis pipeline is integrated with our Southeast Texas System and is an important component to maximizing our Southeast Texas System's profitability. The Oasis pipeline enhances the Southeast Texas System by (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 when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

HPL System

- Capacity of 5.5 Bcf/d
- Approximately 4,350 miles of natural gas pipeline
- Bammel storage facility with 62 Bcf of total working gas capacity

The HPL System is an extensive network of intrastate natural gas pipelines, an 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 is well situated to gather and transport 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.

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, 2011, we had approximately 13.7 Bcf committed under fee-based arrangements with third parties and approximately 48.6 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 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 approximately 540,000 MMBtu/d and 200,000 MMBtu/d, respectively.

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Interstate Transportation Pipelines
The following details our pipelines in the interstate transportation segment.
Transwestern Pipeline

- Capacity of 2.1 Bcf/d
- Approximately 2,690 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Transwestern pipeline is an open-access interstate natural gas pipeline extending from the gas producing regions of West Texas, eastern and northwestern New Mexico, and southern Colorado primarily to pipeline interconnects off the east end of its system and to pipeline interconnects at the California border. The Transwestern pipeline has access to three significant gas basins: the Permian Basin in West Texas and eastern New Mexico; the San Juan Basin in northwestern 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 in Arizona, Nevada and California. Transwestern's Phoenix lateral pipeline, with a throughput capacity of 500 MMcf/d, connects the Phoenix area to the Transwestern mainline.
Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users. Transwestern transports natural gas in interstate commerce.
Tiger Pipeline

- Capacity of 2.4 Bcf/d
- Approximately 195 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Tiger pipeline is an approximately 195-mile interstate natural gas pipeline that connects to our dual 42-inch pipeline system near Carthage, Texas, extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana. The pipeline has a capacity of 2.4 Bcf/d, all of which is sold under long-term contracts ranging from 10 to 15 years.
Fayetteville Express Pipeline

- Capacity of 2.0 Bcf/d
- Approximately 185 miles of interstate natural gas pipeline
- 50/50 joint venture with Kinder Morgan Energy Partners, L.P. ("KMP")

The Fayetteville Express pipeline is an approximately 185-mile interstate natural gas pipeline that originates near Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The pipeline has long-term contracts for 1.85 Bcf/d ranging from 10 to 12 years. The Fayetteville Express pipeline is a 50/50 joint venture with KMP.
Midstream
The following details our assets in the midstream segment.
Southeast Texas System

- Approximately 5,540 miles of natural gas pipeline
- One natural gas processing plant (the La Grange plant) with aggregate capacity of 210 MMcf/d
- 12 natural gas treating facilities with aggregate capacity of 1.6 Bcf/d
- Four natural gas conditioning facilities with aggregate capacity of 650 MMcf/d

The Southeast Texas System is an integrated system that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The La Grange processing plant also processes rich gas from the Eagle Ford Shale. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the East Texas pipeline and is 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.

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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.

Our 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 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

- Approximately 160 miles of natural gas pipeline
- One natural gas processing plant (the Godley plant) with aggregate capacity of 480 MMcf/d
- One natural gas conditioning facility with capacity of 100 MMcf/d

The North Texas System is an 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 processing plant, which processes rich natural gas produced from the Barnett Shale and is integrated with the North Texas System and the ET Fuel System. The facility consists of a cryogenic processing plant and a conditioning facility.

Canyon Gathering System

- Approximately 1,390 miles of natural gas pipeline
- Five natural gas conditioning facilities with aggregate capacity of 96 MMcf/d

The Canyon Gathering System consists of gathering pipeline ranging in diameters from two inches to 24 inches in the Piceance and Uinta Basins of Colorado and Utah and conditioning plants.

Northern Louisiana

- Approximately 240 miles of natural gas pipeline
- Three natural gas treating facilities with aggregate capacity of 385 MMcf/d

Our Northern Louisiana assets comprise several gathering systems in the Haynesville Shale with access to multiple markets through interconnects with several pipelines, including our Tiger pipeline. Our Northern Louisiana assets include the Bistineau, Creedence, and Tristate Systems.

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 115 MMcf/d, as well as one conditioning facility. We also own gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

Marketing Operations

We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation 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 suppliers 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 of natural gas, less the costs of transportation.

For the off-system gas, we purchase gas or act as an agent for small independent producers that may 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 positively impact our expansion and acquisition strategy.

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NGL Transportation and Services

The following details our assets in the NGL transportation and services segment. All assets described below are owned by Lone Star, in which we have a 70% interest.

West Texas System

- Capacity of 137,000 Bbls/d
- Approximately 1,170 miles of NGL transmission pipelines

The West Texas System is an intrastate NGL pipeline consisting of 3-inch to 16-inch long-haul, mixed NGLs transportation pipeline that delivers 137,000 Bbls/d of capacity from the Regency Waha Processing Plant in the Permian Basin and our Godley Processing Plant in the Barnett Shale to the Mont Belvieu NGL storage facility.

Mont Belvieu Storage Facility

- Working storage capacity of approximately 43 million Bbls
- Approximately 140 miles of NGL transmission pipelines

The Mont Belvieu storage facility is an integrated liquids storage facility with over 43 million Bbls of salt dome capacity and 23 million Bbls of brine pond capacity, providing 100% fee-based cash flows. The Mont Belvieu storage facility has access to multiple NGL and refined product pipelines, the Houston Ship Channel trading hub, and numerous chemical plants, refineries and fractionators.

Hattiesburg Storage Facility

- Working storage capacity of four million Bbls

The Hattiesburg storage facility is an integrated liquids storage facility with approximately four million Bbls of salt dome capacity, providing 100% fee-based cash flows.

Sea Robin Processing Plant

- One cryogenic processing plant (the Chalmette Plant) with 850 MMcf/d residue capacity and 26,000 Bbls/d NGL capacity
- 20% non-operating interest held by Lone Star

Sea Robin is a cryogenic rich gas processing plant located on the Sea Robin Pipeline in southern Louisiana. The plant, which is connected to nine interstate and four intrastate residue pipelines as well as various deep-water production fields, has a residue capacity of 850 MMcf/d and an NGL capacity of 26,000 Bbls/d.

Refinery Services

- One cryogenic processing plant (the Chalmette Plant) with 54 MMcf/d capacity
- One cryogenic processing plant (the Sorrento Plant) with 28 MMcf/d capacity
- One NGL fractionator with 25,000 Bbls/d capacity
- Approximately 100 miles of NGL pipelines

Refinery Services consists of a refinery off-gas processing and O-grade NGL fractionation complex located along the Mississippi River refinery corridor in southern Louisiana that cryogenically processes refinery off-gas and fractionates the O-grade NGL stream into its higher value components. The O-grade fractionator located in Geismar, Louisiana is connected by approximately 100 miles of pipeline to the Sorrento and Chalmette cryogenic processing plants.

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 strategic 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 and NGL operations, 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.

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We expect that acquisitions in natural gas and NGL operations will be the primary focus of our acquisition strategy going forward. We also anticipate that our natural gas operations will provide internal growth projects of greater scale as demonstrated by our significant number of completed natural gas pipeline projects.

Following is a summary of the business strategies of our core natural gas and NGL related businesses:

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes 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 increase the percentage of our business conducted with third parties under fee-based arrangements in order to provide for stable, consistent cash flows over long contract periods while reducing exposure to changes in commodity prices.

Growth through acquisitions. We intend to continue to make strategic acquisitions in our areas of operation that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing and acquired assets.

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.

Natural gas and crude oil produced at the wellhead contain varying amounts of mixed NGLs. After extraction by a processing plant the mixed NGLs are transported to a facility for fractionation into NGL products such as ethane, propane, butane, and natural gasoline. The NGL products are then delivered to end-users through pipelines, trucks, rail car and barges. End-users of NGL products include petrochemical, refining companies and end-use propane customers.

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 2011 by the Energy Information Administration, total domestic consumption of natural gas is expected to rise to 26.5 Tcf in 2035 compared to 2010 consumption of 24.1 Tcf. The industrial and electricity generation sectors currently account for more than half of natural gas usage in the United States.

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

Natural gas compression. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly 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.

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

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

NGL transportation. NGL transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities.

NGL storage. NGL storage facilities are used for the storage of mixed NGLs, NGL products and petrochemical products owned by third-parties in storage tanks and underground wells, which allow for the injection and withdrawal of such products at various times of the year to meet demand cycles.

NGL Fractionation and Processing. NGL fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.

Competition

The business of providing natural gas gathering, compression, 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.

In markets served by our NGL pipelines, we face competition with other pipeline companies and barge, rail and truck fleet operations. We face competition with other storage facilities based on fees charged and the ability to receive and distribute the customer's products.

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), requirements for collateral under certain circumstances, and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream, and power generation 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. Currently, 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 have been negatively impacted in recent years by economic conditions and the discovery and development of new shale formations. As a result, many of our customers have been negatively impacted. We are diligent in attempting to mitigate credit risk relating to our customers.

During the year ended December 31, 2011, none of our customers individually accounted for more than 10% of our consolidated revenues.

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Regulation

Regulation 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 and Tiger pipelines transport natural gas in interstate commerce and thus both pipelines qualify as a “natural gas company” under the NGA subject to the FERC’s regulatory jurisdiction. We also hold a joint venture interest in the Fayetteville Express pipeline, an NGA-jurisdictional interstate transportation system subject to the FERC’s broad regulatory oversight.

The FERC’s NGA authority includes the power to regulate:

- the certification and construction of new facilities;
- the review and approval of 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.

Under the terms of a prior settlement, Transwestern was required to file a new NGA Section 4 general rate case no later than October 1, 2011. However, on September 2, 2011, the FERC granted Transwestern's request for an extension of the filing date until December 1, 2011. On September 21, 2011, in lieu of filing a new rate case, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. In general, the settlement provides for the continued use of Transwestern's currently effective transportation and fuel tariff rates, with the exception of certain San Juan Lateral fuel rates which will be reduced over a three year period beginning in April 2012. The settlement also resolves certain non-rate matters, and approves Transwestern's use of certain previously approved accounting methodologies. Under the settlement, Transwestern is required to file a new NGA Section 4 rate case on or before October 1, 2014.

In December 2009, the FERC issued an order granting Fayetteville Express Pipeline LLC (“FEP”) authorization to construct and operate the Fayetteville Express pipeline, subject to certain conditions, and FEP accepted the FERC’s certificate. Interim service began on the Fayetteville Express pipeline in the fourth quarter of 2010 and commenced service to all of its firm shippers on December 1, 2010, with the primary term of each firm shipper’s contract commencing by January 1, 2011. The rates charged for services on the Fayetteville Express pipeline are largely governed by long-term negotiated rate agreements. In the certificate order, the FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates.

In April 2010, the application for authority to construct the Tiger pipeline was approved by the FERC and field construction began on the pipeline in June 2010. The Tiger pipeline was placed in service on December 1, 2010. The rates charged for services on the Tiger pipeline are largely governed by long-term negotiated rate agreements. In June 2010, we filed an application for authority to construct and operate a 0.4 Bcf/d expansion of the Tiger pipeline with the FERC and in February 2011 we accepted the FERC’s certificate order authorizing the construction and operation of this expansion and the rate-related arrangements for the services to be provided on this expansion. The expansion was placed in service on August 1, 2011.

The maximum rates to be charged by NGA-jurisdictional natural gas companies and their terms and conditions for service 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. 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.

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Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, 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 FERC 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 ("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.

Regulation of Intrastate Natural Gas and NGL Pipelines. Intrastate transportation of natural gas and NGLs 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 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 has also issued regulations requiring interstate pipelines and certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information. As these posting requirements for major non-interstate pipelines have been vacated on appeal by the U.S. 5th Circuit Court of Appeals, it is not known with certainty whether and to what extent the FERC will continue to attempt to impose such posting requirements. Should the FERC succeed in reimposing these or similar regulations we could be subject 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 rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a customer or TRRC 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.

Regulation of 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

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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.

Regulation of Gathering Pipelines. 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, West Virginia 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 has been the subject of substantial litigation and varying interpretations, 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 complaint-based rate regulation. In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana's Pipeline Operations Section of the Department of Natural Resources' Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities.

Historically, apart from pipeline safety, Louisiana has not acted to exercise this jurisdiction respecting gathering facilities. In Louisiana, our Chalkley System is regulated as an intrastate transporter, and the Louisiana Office of Conservation has determined that our Whiskey Bay System is a gathering system.

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

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination allegations. Our gathering operations could be adversely affected 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.

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("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. In addition, 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 compliance with safety standards during construction and operation of certain the pipelines and subjects the pipelines to regular inspections. Failure to comply with the safety laws and regulations 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 the NGPSA, but does not apply to our intrastate natural gas pipelines. 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. Changes to federal pipeline safety laws and regulations are being considered by Congress and the DOT including changes to the “rural gathering exemption,” which may be restricted in the future. Other safety regulations may be made more stringent and penalties could be increased. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service.

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In addition to existing pipeline safety regulations, on January 3, 2012, President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, that increases pipeline safety regulation. Among other things, the legislation doubles the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1 million to $2 million for a related series of violations, and provides that these maximum penalty caps do not apply to civil enforcement actions; permits the DOT Secretary to mandate automatic or remote controlled shut off valves on new or entirely replaced pipelines; requires the DOT Secretary to evaluate whether integrity management system requirements should be expanded beyond high-consequence areas ("HCAs"), within 18 months of enactment; and provides for regulation of carbon dioxide transported by pipeline in a gaseous state and requires the DOT Secretary to prescribe minimum safety regulations for such transportation.

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 environmental and safety 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.

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 will 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. 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.

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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 (the “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 the EPA on the matter since our acquisition of the predecessor company in 2001. In addition, through our acquisitions of ongoing businesses, we are currently involved in several remediation projects that have cleanup costs and related liabilities. As of December 31, 2011 and 2010, accruals of $13.7 million and $13.8 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 cleanup 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 2025 is $5.7 million, which is included in the total environmental accruals mentioned above. 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 PCB contamination. 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 into regulated waters could result in fines or penalties, as well as significant remedial obligations. We believe that we are in compliance with the Clean Water Act. The regulations for the EPA’s Spill Prevention, Control and Countermeasures (“SPCC”) program were recently modified. 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. On March 30, 2010, the Texas Commission on Environmental Quality ("TCEQ") adopted two revisions to the state implementation plan responding to the EPA's re-designation of the Houston area to a severe ozone non-attainment area. These revisions will require reductions in current emissions. By March 2013, TCEQ is required to develop a plan to address the recent change in the ozone standard from 0.08 parts per million ("ppm") to 0.075 ppm. We expect these efforts will result in the adoption of new regulations that may require additional NOx emissions reductions at large emission sources in the Houston-Galveston ozone non-attainment area.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The

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EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA’s rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, natural gas or NGLs. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. On November 8, 2010, the EPA adopted an expansion of its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. Under the rule reporting of greenhouse gas emissions from such facilities, including many of our facilities, is now required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

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 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 for 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.

Our pipeline operations are subject to regulation by the DOT under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements will result in capital costs of $3.4 million and operating and maintenance costs of $17.9 million over the course of the next year. 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 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.

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In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

Employees

As of January 31, 2012, we employed 1,946 persons, none of which are represented by labor unions. We believe that our relations with our employees are satisfactory. Our retail propane operations were contributed to AmeriGas on January 12, 2012; therefore, our employee headcount as of January 31, 2012 excluded employees of the retail propane operations.

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.

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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 and NGLs;
- the relationship between natural gas and NGL prices;
- the amount of cash distributions we receive with respect to the AmeriGas common units that we own;
- the weather in our operating areas;
- the level of competition from other midstream companies, interstate pipeline companies and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level of our derivative activities.

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

- the level of capital expenditures we make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow under our credit facilities;
- 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, and is not solely a function of profitability, which is affected by non-cash items. As a result, we may declare and/or pay cash distributions during periods when we record net losses.

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

Our Second Amended and Restated Agreement of Limited Partnership (the "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, 2011, ETE owned 50,226,967 ETP Common Units and SUG, as a subsidiary of ETE, is expected to receive $105 million of additional ETP Common Units upon consummation of the Citrus Acquisition. 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 from time to time in one or more public offerings, direct placements or by other means.

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, 2011, we had approximately $7.81 billion of consolidated debt, excluding the credit facilities of our joint ventures. 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 agreements 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 our 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.

Construction of new pipeline 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 growth capital expenditures, including any new pipeline construction 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. 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, 2011, we had approximately $7.81 billion of consolidated debt, excluding the credit facilities of our joint ventures. 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.

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Increases in interest rates could adversely affect our business, results of operations, cash flows and financial condition.
In addition to our exposure to commodity prices, we have exposure to changes in interest rates. As of December 31, 2011, we had approximately $7.81 billion of consolidated debt, excluding the credit facilities of our joint ventures. Approximately $314.4 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 floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.
As of December 31, 2011, we had a total of $1.15 billion of notional amount of forward-starting interest rate swaps outstanding to hedge the anticipated issuance of senior notes in 2012 and 2013. In addition, we had a total of $500 million of notional amount of interest rate swaps that swap a portion of our fixed rate debt to floating.
An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.
The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.
The credit and business risk profiles of our General Partner, and of ETE as the indirect owner of our General Partner, may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our General Partner and ETE 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 and in Regency 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, 2011, ETE and its affiliates held approximately 22% 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 without the consent of the Unitholders. Furthermore, the general partner of our General Partner may transfer its general partner interest in our General Partner to a third party without the consent of the Unitholders. Any new owner of the General Partner or the general partner 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

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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 any interruption of distributions to us may effect our ability to meet our obligations and 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.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to make required payments on the notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. If we are unable to obtain the funds necessary to pay the principal amount at maturity of the notes, we may be required to adopt one or more alternatives, such as a refinancing of the notes. We cannot assure you that we would be able to refinance the notes.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service the notes or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our Available Cash to our Unitholders of record and our General Partner. Available Cash is generally all of our cash on hand as of the end of a quarter, adjusted for cash distributions and net changes to reserves. Our General Partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating subsidiaries in amounts it determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our Unitholders and our General Partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

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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 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 our 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, our 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 that may permit our General Partner to favor its own interests to the detriment of Unitholders.

ETE indirectly owns our General Partner and as a result controls us. ETE also owns the general partner of Regency, a publicly traded partnership with which we compete in the natural gas gathering, processing and transportation business. The directors and officers of our General Partner and its affiliates have fiduciary duties to manage our General Partner in a manner that is beneficial to ETE, the sole owner of our General Partner. At the same time, our General Partner has fiduciary duties to manage us in a manner that is beneficial to our Unitholders. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to ETE as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ETE, Regency or their owners or affiliates over the interest of our Unitholders.

Such conflicts may arise from, among others, the following:

- Our Partnership Agreement limits the liability and reduces the fiduciary duties of our General Partner while also restricting the remedies available to our Unitholders for actions that, without these limitations, might 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.

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- Our General Partner is allowed to take into account the interests of parties in addition to us, including ETE, Regency and their affiliates, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- Our General Partner’s affiliates, including ETE, Regency and their 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, repayments of debt, issuances of equity and debt securities and cash reserves, each of which can affect the amount of cash that is distributed to Unitholders and to ETE.
- Neither our Partnership Agreement nor any other agreement requires ETE or its affiliates, including Regency, to pursue a business strategy that favors us. The directors and officers of the general partners of ETE and Regency have a fiduciary duty to make decisions in the best interest of their members, limited partners and unitholders, which may be contrary to our best interests.
- Some of the directors and officers of ETE who provide advice to us also may devote significant time to the businesses of ETE, Regency and their affiliates and will be compensated by them for their services.
- Our General Partner determines which costs, including allocated overhead costs, are reimbursable by us.
- Our General Partner is allowed to resolve any conflicts of interest involving us and our General Partner and its affiliates, and any resolution of a conflict of interest by our General Partner that is fair and reasonable to us will be deemed approved by all partners and will not constitute a breach of the partnership agreement.
- Our General Partner controls the enforcement of obligations owed to us by it.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our General Partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our General Partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us.
- In some instances, our General Partner may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

In addition, certain conflicts may arise as a result of our pursuing acquisitions or development opportunities that may also be advantageous to Regency. If we are limited in our ability to pursue such opportunities, we may not realize any or all of the commercial value of such opportunities. In addition, if Regency is allowed access to our information concerning any such opportunity and Regency uses this information to pursue the opportunity to our detriment, we may not realize any of the commercial value of this opportunity. In either of these situations, our business, results of operations and the amount of our distributions to our Unitholders may be adversely affected. We cannot assure Unitholders that such conflicts will not occur or that our internal conflicts policy will be effective in all circumstances to protect our commercially sensitive information or to realize the commercial value of our business opportunities.

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. Regency competes with us with respect to our natural gas operations. Additionally, two directors of Regency GP LLC currently serve as directors of LE GP, LLC, the general partner of ETE.

Risks Related to Our Business

We do not control, and therefore may not be able to cause or prevent certain actions by, certain of our joint ventures.

Certain of our joint ventures have their own governing boards, and we may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in our or the joint venture's best interests. Likewise, we may be unable to prevent actions of the joint venture.

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

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

The 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 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 percent-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 percent-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 to 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 the year ended December 31, 2011, the NYMEX settlement price for the prompt month contract ranged from a high of $4.38 per MMBtu to a low of $3.36 per MMBtu. A composite of the Mt. Belvieu average NGLs price based upon our average NGLs composition during our year ended December 31, 2011 ranged from a high of approximately $1.36 per gallon to a low of approximately $1.15 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 on our pipelines 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;
- 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 profitability of certain activities in our NGL and refined products storage business, our NGL transportation business and our off-gas processing and fractionating business are largely dependent upon market demand for NGLs and refined products, which has been volatile, and competition in the market place, both of which are factors that are beyond our control.

Our NGL and refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers. However, a portion of our revenue is derived from fungible storage and throughput arrangements, under which our revenue is more dependent upon demand for storage from our customers. Demand for these services may fluctuate as a result of changes in commodity prices. Our NGL and refined products storage assets are primarily located in the Mont Belvieu area, which is a significant storage distribution and trading complex with multiple industry participants, any one of which could compete for the business of our existing and potential customers. Any loss of business from existing customers or our inability to attract new customers could have an adverse effect on our results of operations.

Revenue from our NGL transportation systems is exposed to risks due to fluctuations in demand for transportation as a result of unfavorable commodity prices and competition from nearby pipelines. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. We may not be able to renew these contracts or execute new customer contracts on favorable terms if NGL prices decline and demand for our transportation services decreases. Any loss of existing customers due to decreased demand for our services or competition from other transportation service providers could have a negative impact on our revenues and have an adverse effect on our results of operations.

Revenue from our off-gas processing and fractionating system in south Louisiana is exposed to risks due to the low concentration of suppliers near our facilities and the possibility that connected refineries may not provide us with sufficient off-gas for processing at our facilities. The connected refineries may also experience outages due to maintenance issues and severe weather, such as hurricanes. We receive revenues primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

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, natural gas and NGLs;
- the level of domestic oil and natural gas production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local 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 trading, 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.

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

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

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

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

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

Our interstate segment derives a significant portion of its revenue from charging its customers for reservation of capacity, which revenues it receives regardless of whether these customers actually use the reserved capacity. Our interstate segment also generates revenue from transportation of natural gas for customers without reserved capacity. If the reserves available through the supply basins connected to our interstate pipelines 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 our interstate pipelines 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, 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.

As of December 31, 2011, our consolidated balance sheet reflected $1.22 billion of goodwill and $331.4 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair 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.

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 our 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. 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, may 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 the year ended December 31, 2011, EnCana Oil and Gas (USA), Inc., Rosetta Resources Operating LP, EnerVest Operating, LLC, and SandRidge Energy Inc. supplied us with approximately 67% of the Southeast Texas System's natural gas supply. For our year ended December 31, 2011, EOG Resources, Inc., affiliates of Chesapeake Energy Corporation, XTO Energy Inc. ("XTO") and EnCana Oil and Gas (USA), Inc., supplied us with approximately 76% 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 several nine- and ten-year fee-based transportation contracts with XTO that terminate through 2019, pursuant to which XTO has committed to transport certain minimum volumes of natural gas on pipelines in our ET Fuel System. We also have an eight-year fee-based transportation contract with Luminant Energy Company LLC ("Luminant") to transport natural gas on the ET Fuel System. We have also entered into two eight-year natural gas storage contracts that terminate in 2012 with Luminant to store natural gas at the two natural gas storage facilities that are part of the ET Fuel System. Each of the contracts with Luminant may be extended by Luminant for two additional five-year terms.

During 2011 Natural Gas Exchange, Inc., EDF Trading North America, Inc., XTO Energy, Inc. and ConocoPhillips collectively accounted for approximately 30% of our intrastate transportation and storage revenues.

With respect to our interstate transportation operations, FEP, an entity in which we own a 50% interest, has 10-12 year agreements 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, we have 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 also have agreements with other shippers that provide for 10-year commitments for firm transportation capacity on the Tiger pipeline totaling approximately 1.4 Bcf/d, bringing the total shipper commitments to approximately 2.4 Bcf/d of firm transportation service in the Tiger pipeline project. 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 2011, Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. ("EnCana"), Shell Energy North America (US), L.P. and Pacific Summit Energy LLC collectively accounted for 37% of our interstate revenues.

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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.

Certain of our assets may become subject to regulation.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. The West Texas Pipeline, which we acquired as part the LDH acquisition, transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGL transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Such services must be provided in a manner that is just, reasonable and non-discriminatory. We believe that this NGL system does not currently provide interstate service and that it is thus not subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA") and the Energy Policy Act of 1992. We cannot guarantee that the jurisdictional status of this NGL pipeline system will remain unchanged. If the West Texas Pipeline became subject to regulation by the FERC, pursuant to the ICA, the FERC's rate-making methodologies may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

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.

FERC has adopted 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, 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

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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 DOT are considering heightened pipeline safety requirements.

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

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

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs. NGA-jurisdictional natural gas companies must charge rates that are 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, 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.

On September 21, 2011, in lieu of filing a new general rate case filing under Section 4 of the NGA, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. Transwestern is required to file a new general rate case on October 1, 2014. However, shippers which were not parties to the settlement have the right to challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint.

Some of the shippers on our interstate pipelines pay rates established pursuant to long-term, negotiated rate transportation agreements. Prospective shippers on our interstate pipelines that elect not to pay a negotiated rate for service may instead choose to pay a cost-based recourse rate. 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.

Any successful challenge to the rates of our interstate natural gas companies, whether the result of a 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 end of the term of our 2011 rate case settlement.

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

In addition to rate oversight, 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 the 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 were required to, among other things, file and support before the FERC NGA Section 7(c) applications for certificates of public convenience and necessity to build, own and operate such facilities. We cannot guarantee that FERC will authorize construction and operation of any future interstate natural gas transportation project we might propose. Moreover, there is no guarantee that certificate authority for any future interstate projects will be granted in a timely manner or will be free from potentially burdensome conditions.

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 and NGL operations are subject to stringent federal, state, and local laws and regulations that seek to protect human health and the environment, including those governing the emission or discharge of materials into the environment. 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 EPA, 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 significant 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. Certain environmental laws and regulations can provide for joint and several strict liability for cleanup to address discharges or releases of petroleum hydrocarbons or other materials or wastes at sites to which we may have sent wastes or 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 2025 was $5.7 million as of December 31, 2011.

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 ppm to 0.075 ppm, 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. We have previously been able to satisfy the more stringent

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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.

Recently proposed rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On July 28, 2011, the U.S. Environmental Protection Agency ("EPA") proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's proposed rule package includes New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA must take final action on the proposed rules by February 28, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules will be required within three years of publication of the final rules, and it could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our transportation, storage, and midstream services.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA’s rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, natural gas or NGLs. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

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 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 for 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 temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could 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.
The recent adoption of financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.
The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In December 2011, the CFTC extended temporary exemptive relief from certain swap regulation provisions of the legislation until July 16, 2012. The CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. It is not possible at this time to predict when the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure its existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.
We may be impacted by competition from other midstream and transportation and storage 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 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, 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.

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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, 2011, approximately 31% 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 natural gas storage business may depend on neighboring pipelines to transport natural gas.

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

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

Our 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 $3.4 million and operating and maintenance costs of $17.9 million over the course of the next year. For the years ended December 31, 2011, 2010 and 2009, $18.3 million, $13.3 million and $31.4 million, respectively, of capital costs and $14.7 million, $15.4 million and $18.5 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will

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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.

Changes in other forms of health and safety regulations are also being considered. New pipeline safety legislation requiring more stringent spill reporting and disclosure obligations has been introduced in the U.S. Congress and was passed by the U.S. House of Representatives in 2010, but was not voted on in the U.S. Senate. Similar legislation is likely to be considered in the current session of Congress. The DOT has also recently proposed legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules, which is in addition to the PHMSA's announced intention to strengthen its rules. Such Legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

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.

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.

We have a significant equity investment in AmeriGas and the value of this investment, and the cash distributions we expect to receive from this investment, are subject to the risks encountered by AmeriGas with respect to its business.

In January 2012, we consummated the contribution of the Propane Business to AmeriGas in exchange for consideration of approximately $1.46 billion in cash and approximately 29.6 million AmeriGas common units, plus the assumption of approximately $71 million of existing HOLP debt. The value of our investment in AmeriGas common units and the cash distributions we expect to receive on a quarterly basis with respect to these common units are subject to the risks encountered by AmeriGas with respect to its business, including the following:

- adverse weather condition resulting in reduced demand;
- cost volatility and availability of propane, and the capacity to transport propane to its customers;
- the availability of, and its ability to consummate, acquisition or combination opportunities;
- successful integration and future performance of acquired assets or businesses;

- changes in laws and regulations, including safety, tax, consumer protection and accounting matters;
- competitive pressures from the same and alternative energy sources;
- failure to acquire new customers and retain current customers thereby reducing or limiting any increase in revenues;

- liability for environmental claims;
- increased customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand;
- adverse labor relations;
- large customer, counter-party or supplier defaults;
- liability in excess of insurance coverage for personal injury and property damage arising from explosions and other catastrophic events, including acts of terrorism, resulting from operating hazards and risks incidental to transporting, storing and distributing propane, butane and ammonia;
- political, regulatory and economic conditions in the United States and foreign countries;
- capital market conditions, including reduced access to capital markets and interest rate fluctuations;
- changes in commodity market prices resulting in significantly higher cash collateral requirements;
- the impact of pending and future legal proceedings;
- the timing and success of its acquisitions and investments to grow its business; and
- its ability to successfully integrate acquired businesses and achieve anticipated synergies.

Our pipelines may be subject to more stringent safety regulation.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, became effective. The new law requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The law requires numerous studies and/or the development of rules over the next two years covering the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related rules. The DOT has already proposed rules that address many areas of the newly adopted legislation. Any regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

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 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.

The present tax treatment of publicly traded partnerships, including us, or an investment in our Common Units, may be modified by administrative, legislative or judicial interpretation at any time, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, recently, members of the U.S. Congress considered substantive changes to the existing U.S. federal income tax laws that would have affected the tax treatment of certain publicly traded partnerships. Several states currently impose entity-level taxes on partnerships, including us. Further, because of widespread state budget deficits and other reasons, several additional states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. If any additional states were to impose a tax upon us as an entity, our cash available for distribution would be reduced. Any modification to the U.S. federal income or state tax laws, or interpretations thereof, may or may not be applied retroactively. Although we are unable to predict whether any of these changes

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or any other proposals 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.

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

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

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

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, may be taxable to them as "unrelated business taxable income." Distributions to non-U.S. persons will be reduced by withholding taxes, generally at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal and state income tax returns and generally pay United States federal and state income 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. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

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

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

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 technically 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 technical termination would, among other things, result in the closing of our taxable year for all Unitholders which would require us to file two federal partnership 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

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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 on the technical termination date, 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. We currently own property or conduct business in more than 40 states, either directly or indirectly as a result of our investment in AmeriGas. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. 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.

Risks Related to the Proposed Citrus Acquisition

Our acquisition of the 50% interest in Citrus is subject to the satisfaction of certain conditions to closing, one of which is the completion of the merger of SUG and a subsidiary of ETE.

Our acquisition of the 50% interest in Citrus Corp. currently owned by SUG is subject to the satisfaction of certain conditions to closing, including the absence of a material adverse change to the business or results of operations of Citrus Corp. subsequent to January 1, 2012, the receipt of necessary governmental approvals and the completion of the merger of SUG and a wholly-owned subsidiary of ETE. The completion of the merger of SUG and the subsidiary of ETE is subject to the absence of a material adverse change to the business or results of operation of ETE and SUG, the receipt of necessary regulatory approvals and the satisfaction or waiver of other conditions specified in the SUG Merger Agreement. In the event those conditions to closing are not satisfied or waived, we would not complete the acquisition of the 50% interest in Citrus Corp. currently owned by SUG.

Any acquisition we complete, including the Citrus Acquisition, is subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to Unitholders.

Any acquisition we complete, including the proposed Citrus Acquisition, involves potential risks, including, among other things:

- the validity of our assumptions about revenues, capital expenditures and operating costs of the acquired business or assets, as well as assumptions about achieving synergies with our existing businesses;
- a significant increase in our interest expense and financial leverage resulting from any additional debt incurred to finance the acquisition consideration, which could offset the expected accretion to our Unitholders from such acquisition and could be exacerbated by volatility in the credit or debt capital markets;
- a failure to realize anticipated benefits, such as increased distributable cash flow per unit, enhanced competitive position or new customer relationships;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- difficulties operating in new geographic areas or new lines of business;
- the incurrence or assumption of 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;
- the inability to hire, train or retrain qualified personnel to manage and operate our growing business and assets, including any newly acquired business or assets;
- the diversion of management's attention from our existing business; and
- the incurrence of 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.

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Also, our reviews of businesses or assets proposed to be acquired are inherently incomplete because it generally is not feasible to perform an in-depth review of businesses and assets involved in each acquisition given time constraints imposed by sellers. Even a detailed review of assets and businesses may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the assets or businesses to fully assess their deficiencies and potential. Inspections may not always be performed on every asset, and environmental problems are not necessarily observable even when an inspection is undertaken.

In connection with the proposed Citrus Acquisition, we incurred substantial additional indebtedness.

The Citrus Merger Agreement requires that we pay $1.895 billion to ETE as cash consideration for the interest in Citrus. In January 2012, we issued $2.0 billion of senior notes and we plan to use net proceeds from this issuance to fund this cash payment. The incurrence of this additional indebtedness increased our overall level of debt and adversely affected our ratios of total indebtedness to EBITDA and EBITDA to interest expense, both on a current basis and a pro forma basis taking into account our acquisition of the 50% interest in Citrus. If we do not consummate the acquisition of the 50% interest in Citrus on or before April 17, 2012, or the Citrus Merger Agreement is terminated on or before such date, we must redeem the $2.0 billion of senior notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest.

Class action stockholder litigation could prevent or delay completion of the SUG Merger and/or the Citrus Acquisition, and a third party is seeking rescission of the Citrus Acquisition or damages in connection therewith.

In connection with the SUG Merger, purported stockholders of SUG have filed several stockholder class action lawsuits against ETE, SUG, and the SUG Board of Directors in the District Courts of Harris County, Texas and in the Delaware Courts of Chancery. Among other remedies, the plaintiffs may seek to enjoin the SUG Merger. If a final settlement is not reached, or if a dismissal is not obtained, these lawsuits could prevent or delay completion of the SUG Merger, which in turn could prevent or delay the completion of the Citrus Acquisition.

On November 28, 2011, the W.J. Garrett Trust filed a lawsuit in the 234th District Court of Harris County, Texas derivatively on behalf of ETP unitholders challenging the Citrus Acquisition and the contribution of our Propane Business to AmeriGas. The suit names ETP, ETE, SUG and the directors of both ETP and ETE as defendants. Specifically, the plaintiff alleges that the Citrus Acquisition and the contribution of the Propane Business to AmeriGas involved an unfair price and alleges deficiencies in the process by which the named directors and officers conducted those transactions. Additionally, the plaintiff alleges that (i) the named directors and officers breached their fiduciary and contractual duties in connection with the transactions; (ii) the named entities aided and abetted these breaches of the directors' and officers' fiduciary and contractual duties; (iii) SUG and ETE tortiously interfered with ETP's partnership agreement; and (iv) the defendants conspired to breach their fiduciary and contractual duties. On January 30, 2012, the defendants filed a motion challenging the sufficiency of the plaintiff's claim. A hearing on the defendants' motion is set for March 5, 2012 and trial is set for January 14, 2013. At this time, we are unable to predict the likelihood of an unfavorable outcome or any estimate of potential loss with respect to this matter.

CrossCountry, the SUG subsidiary directly holding the 50% interest in Citrus Corp., filed a petition in the Delaware Court of Chancery seeking a declaratory judgment against El Paso, the owner of the other 50% interest of Citrus Corp. This petition was filed by CrossCountry following an exchange of letters between CrossCountry, El Paso and Southern Union in which El Paso stated that it believed the Citrus Acquisition violated the provisions of the Capital Stock Agreement of Citrus Corp., dated June 30, 1986. Specifically, while not seeking an injunction of the merger, El Paso claims that the Citrus Acquisition violates El Paso's right of first refusal and seeks rescission of the Citrus Acquisition or, alternatively, damages. If El Paso is ultimately successful in asserting its position with respect to the terms of the Capital Stock Agreement, we cannot predict whether the court would determine that rescission would be an appropriate remedy or would otherwise award damages to El Paso and, if so, the amount of any such damages.

Additional lawsuits may be filed against ETE and/or SUG related to the SUG Merger or against ETP and/or ETE related to the Citrus Acquisition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in “Item 1. Business.” We own an office building for our executive office in Dallas, Texas and office buildings in Houston and San Antonio, Texas. 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.

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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.

Substantially all of our pipelines, which are described in "Item 1. Business" 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 multiple natural gas and NGL storage facilities and own or lease other processing, treating and conditioning facilities in connection with our midstream operations.

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 we and they are subject.

For a description of legal proceedings, see Note 8 to our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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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 2011			
Fourth Quarter	$47.69	$38.08	$0.89375
Third Quarter	49.50	40.25	0.89375
Second Quarter	55.20	44.75	0.89375
First Quarter	55.50	50.31	0.89375
Fiscal Year 2010			
Fourth Quarter	$52.00	$48.01	$0.89375
Third Quarter	51.95	44.97	0.89375
Second Quarter	49.99	40.06	0.89375
First Quarter	47.76	42.69	0.89375

(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" below for a discussion of our policy regarding the payment of distributions.

Description of Units

As of February 15, 2012, there were approximately 330,000 individual Common Unitholders, which includes Common Units held in street name. 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. As the Class E Units are owned by a wholly owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements. Although no plans are currently in place, management may evaluate whether to retire the Class E Units at a future date.

As of December 31, 2011, our General Partner owned an approximate 1.5% general partner interest in us and the holders of Common Units and Class E Units collectively owned a 98.5% limited partner interest in us.

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

Cash Distribution Policy

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

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

- Less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to
  - provide for the proper conduct of our business;
  - comply with applicable law 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.

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");

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- 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.

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."

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 be reduced to 50% of the 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 additional taxation as an entity for federal, state or local income tax purposes, under the terms of the Partnership Agreement, we can 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 6 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

None.

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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 "Item 7. 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, 2007	Year Ended August 31, 2007
	2011	2010	2009	2008		
Statement of Operations Data:						
Total revenues	$6,850,440	$5,884,827	$5,417,295	$9,293,868	$2,349,510	$6,792,037
Operating income	1,244,807	1,058,171	1,127,607	1,117,579	323,634	829,652
Income from continuing operations	697,162	617,222	791,542	866,023	261,824	677,281
Basic net income per limited partner unit	1.10	1.20	2.53	3.74	1.24	3.32
Diluted net income per limited partner unit	1.10	1.19	2.53	3.74	1.24	3.31
Cash distributions per unit	3.58	3.58	3.58	3.55	1.13	3.19
Balance Sheet Data (at period end):						
Total assets	15,518,616	12,149,992	11,734,972	10,627,489	9,008,161	7,708,428
Long-term debt, less current maturities	7,388,170	6,404,916	6,176,918	5,618,549	4,297,264	3,626,977
Total equity	6,350,424	4,743,437	4,599,708	3,743,069	3,379,191	3,042,072
Other Financial Data:						
Capital expenditures:						
Maintenance (accrual basis)	134,164	99,275	102,652	140,968	48,998	89,226
Growth (accrual basis)	1,375,523	1,288,863	530,333	1,921,679	604,371	998,075
Cash (received in) paid for acquisitions	1,971,581	177,920	(30,367)	84,783	337,092	90,695

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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. Financial Statements and Supplementary Data" 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.
References to "we," "us," "our", the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

Overview

The activities and the wholly-owned operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including 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"); and
  - interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC ("ET Interstate"). ET Interstate is the parent company of Transwestern Pipeline Company, LLC ("Transwestern"), ETC Fayetteville Express Pipeline, LLC ("ETC FEP") and ETC Tiger Pipeline, LLC ("ETC Tiger").
- NGL transportation, storage and fractionation services primarily through Lone Star NGL LLC ("Lone Star").
- Retail propane through Heritage Operating, L.P. ("HOLP") and Titan Energy Partners, L.P. ("Titan").
- Other operations, including natural gas compression services.

Recent Developments

Propane Operations

On January 12, 2012 we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business"), to AmeriGas Partners, L.P. ("AmeriGas"). We received approximately $1.46 billion in cash and 29.6 million AmeriGas common units. AmeriGas also assumed approximately $71 million of existing HOLP debt.

Citrus Acquisition

On July 19, 2011, we entered into the Amended Citrus Merger Agreement pursuant to which it is anticipated that Southern Union Company, a Delaware corporation ("SUG"), will cause the contribution to us of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission ("FGT") pipeline system, in exchange for approximately $1.895 billion in cash and $105 million of our Common Units, contemporaneous with the completion of the merger between SUG and ETE pursuant to the SUG Merger Agreement.

Expansion of Rich Eagle Ford Mainline

In February 2012, we announced our entry into multiple long-term, fee-based agreements with producers to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale in south Texas. To facilitate the agreements, we will further expand the REM pipeline and construct a new processing facility at an expected cost of $210 million. The pipeline expansion announced in February 2012 is expected to be completed in the fourth quarter of 2013, and the processing facility announced in February 2012 is expected to be completed in the fourth quarter of 2012.

Construction of Second Fractionator at Lone Star's Mont Belvieu Fractionation Facility

In February 2012, Lone Star announced the construction of a second 100,000 Bbls/d fractionation facility at Mont Belvieu , Texas. Supported by multiple long-term contracts, the second fractionator is necessary to handle the increasing NGL barrels delivered via the partnership's Woodford Shale, Eagle Ford Shale and Permian Basin infrastructure, including Lone Star's 570-mile West Texas Gateway NGL Pipeline. This second fractionation facility is expected to be completed in the first quarter of 2014 at an estimated cost of $350 million.

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2012 Financing Transactions

In January 2012, we issued $2.0 billion principal amount of Senior Notes, the proceeds from which we anticipate using to fund the cash potion of the Citrus Acquisition and for general partnership purposes. In January and February 2012, we also completed the repurchase of approximately $750 million of our Senior Notes.

General

Our primary objective is to increase the level of our distributable cash flow over time by pursuing a business strategy that is currently focused on growing our natural gas and NGL businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets as demonstrated by our acquisition with Regency of LDH Energy Asset Holdings LLC ("LDH"), our pending Citrus Acquisition and our recent announcements regarding organic growth projects. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

During the past several years, we have been successful in completing several transactions that have increased our distributable cash flow. 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 available for distributions to our Partnership for years to come.

Our principal operations as of December 31, 2011 included the following segments:

- Intrastate natural gas transportation and storage – Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are primarily among receipt points between West Texas to East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and fuel retention. Excess fuel retained after consumption, if any, is typically sold at market prices. In addition to transport fees, we generate revenue from purchasing natural gas and transporting it across our system. The natural gas is then sold to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System purchases natural gas at the wellhead for transport and selling. Other pipelines with access to West Texas supply, such as Oasis and ET Fuel, may also purchase gas at the wellhead and other supply sources for transport across our system to be sold at market on the east side of our system. This activity allows our intrastate transportation and storage segment to capture the current basis differentials between delivery points on our system or to capture basis differentials that were previously locked in through hedges. Firm capacity long-term contracts are typically not subject to price differentials between shipping locations.

We also 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 inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used 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. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward 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 of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and 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 prior to withdrawal of the gas, we will record unrealized losses or lower unrealized gains.

As noted above, any excess retained fuel is sold at market prices. To mitigate commodity price exposure, we will use financial derivatives to hedge prices on a portion of natural gas volumes retained. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's unreserved capacity. Gains and losses on these financial derivatives are dependent on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings. During the fourth quarter of 2011, we began using derivatives for trading purposes.

- Interstate natural gas transportation – The majority of our interstate transportation revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Tiger, Fayetteville Express Pipeline LLC ("FEP") and Transwestern expansion shippers have made 10- to 15-year commitments to pay reservation charges for the firm capacity reserved for their use. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.
- 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, we retain a portion of the natural gas and NGLs processed, or a portion of the proceeds of the sales of those commodities, as a fee. When natural gas and NGL prices increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGLs decrease, so does the value of the portion we retain as a fee. For wellhead (keep-whole) contracts, we retain the difference between the price of NGLs and the cost of the gas to process the NGLs. 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 become negative; however, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs in the event it is uneconomical to process this gas. Our processing contracts and wellhead purchases in rich natural gas areas provide that we earn and take title to specified volumes of NGLs, which we also refer to as equity NGLs. Equity NGLs in our midstream segment are derived from performing a service in a percent-of-proceeds contract or produced under a keep-whole arrangement.

In addition to NGL price risk, our processing activity is also subject to price risk from natural gas because, in order to process the gas, in some cases we must purchase it. Therefore, lower gas prices generally result in higher processing margins.

We conduct marketing operations in which we market certain of 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 does not originate from 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 suppliers 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 of natural gas, less the costs of transportation.

- NGL transportation and services – NGL transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL products that are commingled in a storage cavern with other customers' products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns.

This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an O-grade stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percentage-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percentage-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and

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olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee.

- Retail propane and other retail propane related operations – Revenue is principally generated from the sale of propane and propane-related products and services. 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. We use information published by the National Oceanic and Atmospheric Administration ("NOAA") to gather heating degree day data to analyze how our sales volumes may be affected by temperature. Our normal temperatures are defined as the prior ten year weighted-average temperature which is based on the average heating degree days provided by NOAA gathered from the various measuring points in our operating areas weighted by the retail volumes attributable to each measuring point.

Trends and Outlook

We intend to continue to maintain sufficient liquidity to allow us to fund growth projects and acquisitions as such new projects and acquisitions are identified in the future. To that end, we have secured financing for the Citrus Acquisition, which we expect to consummate in the near term, by issuing $2.0 billion of senior notes in January 2012. We also completed the contribution of our Propane Business in January 2012, which not only improved our liquidity, but also allows us to focus on our core businesses in the natural gas and NGL markets. The completion of the LDH Acquisition in 2011 marked our entry into NGL transportation and related services, which expands our business mix that had previously been predominantly focused on natural gas. We expect to continue development of the NGL business in order to take advantage of the currently strong environment.

With respect to industry trends, we expect to see continued high natural gas storage levels and continued growth in natural gas supply. Much of the growth in supply is due to the continued discovery and development of new natural gas shale formations as well as natural gas associated with wells targeting liquids production. We expect overall consumption of natural gas in the United States to be stable during 2012. 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 capacity reservation fees regardless of the volume of natural gas transported; however, we do recognize a portion of our revenue from fees based on volumes transported. We expect these volumes to be relatively consistent with 2011 with a downward trend in areas where we have assets connected to dry gas given the outlook on natural gas prices and production in 2012.

We continue to evaluate and execute strategies to mitigate the effects of changing prices. These strategies include hedging net retained fuel volumes. As of January 31, 2012, all of our estimated 2012 and 2013 net retained fuel volumes were hedged. We also benefit from price differentials between receipt and delivery points on our system. These differentials are a driver of volumes from certain of our customers and we also can capture price differentials on our open capacity. We do not expect a significant change in price differentials between locations our assets are connected to during 2012 based on current supply, demand and capacity dynamics.

With our expansion of activities in the Eagle Ford Shale and Permian Basin, we expect growth in margin from our midstream segment as we continue to meet our customers' needs in these rich natural gas shale formations. We also anticipate NGL prices to be stable during 2012 given strong underlying fundamentals.

Results of Operations

We previously reported segment operating income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

When presented on a consolidated basis, Adjusted EBITDA is a non-GAAP measure. Although we include Segment Adjusted EBITDA in this report, we have not included an analysis of the consolidated measure, Adjusted EBITDA.

We have included a total of Segment Adjusted EBITDA for all segments, which is reconciled to the GAAP measure of net income in the consolidated results sections that follow.

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Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010 (tabular dollar amounts are expressed in thousands)

Consolidated Results

	Years ended December 31, 2011	2010	Change
Segment Adjusted EBITDA			
Intrastate transportation and storage	$667,294	$716,176	$(48,882)
Interstate transportation	373,409	220,027	153,382
Midstream	388,578	329,025	59,553
NGL transportation and services	88,197	—	88,197
Retail propane and other retail propane related	222,204	269,670	(47,466)
All other	2,881	5,990	(3,109)
Total Segment Adjusted EBITDA	1,742,563	1,540,888	201,675
Depreciation and amortization	(430,904)	(343,011)	(87,893)
Interest expense, net of interest capitalized	(474,113)	(412,553)	(61,560)
Gains (losses) on non-hedged interest rate derivatives	(77,409)	4,616	(82,025)
Income tax expense	(18,815)	(15,536)	(3,279)
Non-cash compensation expense	(37,457)	(27,180)	(10,277)
Allowance for equity funds used during construction	957	28,942	(27,985)
Unrealized losses on commodity risk management activities	(11,407)	(78,300)	66,893
Impairment of investments in affiliates	(5,355)	(52,620)	47,265
Losses on disposal of assets	(3,188)	(5,043)	1,855
Adjusted EBITDA attributable to noncontrolling interest	37,842	—	37,842
Proportionate share of unconsolidated affiliates' interest, depreciation and allowance for equity funds used during construction	(29,994)	(22,499)	(7,495)
Other, net	4,442	(482)	4,924
Net income	$697,162	$617,222	$79,940

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased due to acquisitions and assets placed in service since 2010. Depreciation and amortization increased by $28.3 million for our interstate transportation segment primarily due to the Tiger pipeline which was placed in service in December 2010. Depreciation and amortization increased by $25.3 million for midstream segment primarily due to incremental depreciation from the continued expansion of our Louisiana and South Texas assets. Depreciation and amortization for our NGL transportation and services segment was $32.5 million from its inception in May 2011 through December 31, 2011.

Interest Expense. Interest expense increased primarily due to the issuance of $1.5 billion of senior notes in May 2011, the proceeds from which were used to repay borrowings on our revolving credit facility, to fund growth projects and for general partnership purposes. Interest expense was presented net of capitalized interest and allowance for debt funds used during construction, which totaled $12.8 million and $16.3 million during 2011 and 2010, respectively.

Gains (Losses) on Non-Hedged Interest Rate Derivatives. The year ended December 31, 2011 reflected losses on non-hedged interest rate swaps for which we had total notional amounts outstanding of $1.65 billion as of December 31, 2011, which included $1.15 billion of forward-starting floating-to-fixed swaps used to hedge interest rates associated with anticipated note issuances and $500 million of fixed-to-floating swaps used to swap a portion of our fixed rate debt to floating. During the second half of 2011, forward rates decreased significantly due to global economic uncertainty which resulted in unrealized non-cash losses on our forward-starting floating-to-fixed swaps.

Income Tax Expense. The increase in income tax expense between the periods was primarily due to increases in taxable income within our subsidiaries that are taxable corporations, in addition to an increase in amounts recorded for the Texas margins tax resulting from increased operating income.

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Non-Cash Compensation Expense. The increase in non-cash compensation expense was due to an increase in the number of restricted unit awards granted.

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction for 2011 reflected amounts recorded in connection with the expansion of the Tiger pipeline, which was completed in August 2011, whereas 2010 reflected amounts recorded in connection with the original construction of the Tiger pipeline.

Unrealized Losses on Commodity Risk Management Activities. See discussion of the unrealized loss on commodity risk management activities included in the discussion of segment results below.

Impairment of Investments in Affiliates. For 2011, our results reflected a non-cash charge to write off all of our investment in a joint venture for which projects are no longer being pursued. During 2010, in conjunction with the transfer of our interest in Midcontinent Express Pipeline on May 26, 2010, we recorded a non-cash charge of approximately $52.6 million to reduce the carrying value of our interest to its estimated fair value.

Adjusted EBITDA Attributable to Noncontrolling Interest. The amount reflected for 2011 represents the proportionate share of Lone Star's Adjusted EBITDA attributable to Regency's 30% interest in Lone Star. This amount was excluded from the measure of Segment Adjusted EBITDA. Net income includes the results attributable to Lone Star on a consolidated basis.

Proportionate Share of Unconsolidated Affiliates' Interest, Depreciation and Allowance for Equity Funds Used During Construction. Amounts reflected for 2011 and 2010 primarily represent our proportionate share of such amounts for FEP for both periods and Midcontinent Express Pipeline LLC ("MEP") for 2010. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

Segment Operating Results

Our reportable segments are discussed below. “All other” includes our compression and wholesale propane businesses. We evaluate segment performance based on Segment Adjusted EBITDA, 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.

The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

- Gross margin, operating expenses, and selling, general and administrative. These line items are the amounts included in our consolidated financial statements that are attributable to each segment.

- Unrealized gains or losses on commodity risk management activities. These are the unrealized amounts that are included in cost of products sold to calculate gross margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

- Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.

- Adjusted EBITDA related to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA above.

- Adjusted EBITDA attributable to noncontrolling interest. These amounts represent the portion of Segment Adjusted EBITDA attributable to noncontrolling interest. Currently, the only noncontrolling interest in ETP is the 30% interest in Lone Star that is held by Regency. We reflect this amount as noncontrolling interest because we consolidate 100% of Lone Star on our consolidated financial statements.

For additional information regarding our business segments, see “Item 1. Business” and Notes 1 and 12 to our consolidated financial statements. In addition, following the acquisition of all of the membership interests in LDH on May 2, 2011, we have added an NGL transportation and services segment, which includes all of Lone Star’s results of operations.

Selling, General and Administrative Expenses Not Allocated to Segments. 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 our actual expenses from previous months and

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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.

Intrastate Transportation and Storage

	Years Ended December 31,		
	2011	2010	Change
Natural gas MMBtu/d — transported	11,295,084	12,251,457	(956,373)
Revenues	$2,674,157	$3,290,905	$(616,748)
Cost of products sold	1,774,006	2,381,397	(607,391)
Gross margin	900,151	909,508	(9,357)
Unrealized losses on commodity risk management activities	9,994	62,370	(52,376)
Operating expenses, excluding non-cash compensation expense	(191,488)	(194,955)	3,467
Selling, general and administrative, excluding non-cash compensation expense	(53,982)	(63,454)	9,472
Adjusted EBITDA related to unconsolidated affiliates	2,619	2,707	(88)
Segment Adjusted EBITDA	$667,294	$716,176	$(48,882)

Volumes. Transported volumes decreased due to a less favorable natural gas price environment and lower basis differentials primarily between the West and East Texas market hubs offset by increased volumes from rich natural gas shale formations primarily in the Eagle Ford and certain areas of the Barnett Shale. The average spot price difference between these locations was $0.036/MMBtu in 2011 compared to $0.127/MMBtu in 2010.

Gross Margin. The components of our intrastate transportation and storage segment gross margin were as follows:

	Years Ended December 31,		
	2011	2010	Change
Transportation fees	$599,380	$594,405	$4,975
Natural gas sales and other	107,007	110,002	(2,995)
Retained fuel revenues	129,712	143,606	(13,894)
Storage margin, including fees	64,052	61,495	2,557
Total gross margin	$900,151	$909,508	$(9,357)

In 2011, our gross margin decreased as compared to 2010 due to the net impact of the following factors:

- Additional demand-based contracts offset a decline in transported volumes, resulting in a net increase of $5 million in transportation fees.
- From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $35.7 million in 2011 compared to $40.0 million in 2010. The decrease of $4.2 million between periods was primarily due to a reduction in the amount of capacity utilized by our marketing affiliate.
- Margin from natural gas sales and other activity decreased $3.0 million in 2011 as compared to 2010 primarily due to unfavorable impacts from system optimization activities.

The margin from the natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. During the fourth quarter of 2011, our trading activities included the use of financial commodity derivatives. Excluding derivatives related to storage, unrealized losses of $21.3 million were recorded in 2011 compared to unrealized losses of $13.3 million in 2010.

- Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased $13.9 million due to less volumes and a decline in average natural gas spot prices, which averaged $4.03/MMBtu in 2011 compared to an average of $4.35/MMBtu in 2010.

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Storage margin was comprised of the following:

	Years Ended December 31,		
	2011	2010	Change
Withdrawals from storage natural gas inventory (MMBtu)	24,517,008	39,784,446	(15,267,438)
Margin on physical sales	$10,433	$68,661	$(58,228)
Settlements of derivatives	8,332	1,517	6,815
Realized margin on natural gas inventory transactions	18,765	70,178	(51,413)
Fair value inventory adjustments	(51,529)	(57,157)	5,628
Unrealized gains on derivatives	62,875	8,842	54,033
Margin recognized on natural gas inventory, including related derivatives	30,111	21,863	8,248
Revenues from fee-based storage	34,449	40,674	(6,225)
Other costs	(508)	(1,042)	534
Total storage margin	$64,052	$61,495	$2,557

The increase in our storage margin was principally driven by gains in derivatives offsetting a decline in the margin on physical sale due to a decrease in withdrawals of natural gas from our Bammel storage facility as a result of warmer than normal weather patterns. Additionally, we experienced a decline in fee-based storage revenue due to the cessation in 2011 of fixed fee contracts representing 4.5 Bcf of storage capacity.

Unrealized Losses on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities reflect the net impact from unrealized gains and losses on storage and non-storage derivatives, as well as fair value adjustments on inventory. Unrealized losses decreased in 2011 compared to 2010 primarily due to the timing of storage withdrawals and declining forward prices. We also recorded additional mark-to-market losses of $8.0 million in 2011 not related to storage.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased between the periods primarily due to a decrease in the cost of natural gas consumed of $1.3 million due to lower gas prices and a decrease of $6.6 million in operating and maintenance expense compared to 2010. These decreases were partially offset by higher ad valorem taxes of $1.7 million due to expansions on our HPL system and increased employee costs of $2.7 million.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses decreased between the periods primarily due to a decrease in allocated overhead expenses. A lower amount of overhead expenses were allocated to the intrastate transportation and storage segment in 2011 because of growth in other segments and the addition of NGL transportation and services segment.

Interstate Transportation

	Years Ended December 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	2,800,655	1,616,762	1,183,893
Natural gas sold (MMBtu/d)	22,405	23,760	(1,355)
Revenues	$446,743	$292,419	$154,324
Operating expenses, excluding non-cash compensation expense	(92,261)	(83,740)	(8,521)
Selling, general and administrative, excluding non-cash compensation expense	(34,485)	(20,171)	(14,314)
Adjusted EBITDA related to unconsolidated affiliates	53,412	31,519	21,893
Segment Adjusted EBITDA	$373,409	$220,027	$153,382

Volumes. Transported volumes for our interstate transportation segment increased primarily due to an increase in transported volumes of 1,270,656 MMBtu/d on the Tiger pipeline in 2011. The Tiger pipeline was placed in service in

December 2010, and the Tiger pipeline expansion was placed in service on August 1, 2011. The incremental transported volumes related to the Tiger pipeline were offset by lower volumes on the Transwestern pipeline.

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Revenues. Interstate transportation revenues increased as a result of incremental revenues from the Tiger pipeline and related expansion. Revenues from the Tiger pipeline totaled $188.2 million in 2011 compared to $10.2 million in 2010. The incremental revenues from the Tiger pipeline were offset by a decrease in revenues from the Transwestern pipeline of $23.7 million due to decreases in transportation fees and operations gas sales as a result of lower volumes and prices.

Operating Expenses, Excluding Non-Cash Compensation Expense. Interstate transportation operating expenses increased primarily due to operating expenses incurred on the Tiger pipeline.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Interstate transportation selling, general and administrative expenses increased primarily due to increased allocated and employee-related expenses, including incremental amounts related to the Tiger pipeline.

Adjusted EBITDA Related to Unconsolidated Affiliates. Amounts reflected for 2011 primarily represent our proportionate share of such amounts recorded by FEP. Amounts reflected for 2010 primarily represent our proportionate share of such amounts recorded by MEP. We transferred substantially all of our interests in MEP to ETE on May 26, 2010, prior to which we held a 50% interest in MEP. We recorded equity in earnings related to FEP of $23.9 million in 2011 and equity in earnings related to MEP of $9.0 million in 2010. In 2011, FEP recorded (on a 100% basis) revenues of $121.8 million and net income of $47.8 million.

Midstream

	Years Ended December 31,		
	2011	2010	Change
NGLs produced (Bbls/d)	54,925	51,144	3,781
Equity NGLs produced (Bbls/d)	16,851	19,301	(2,450)
Revenues	$2,593,383	$3,169,314	$(575,931)
Cost of products sold	2,085,951	2,759,113	(673,162)
Gross margin	507,432	410,201	97,231
Unrealized (gains) losses on commodity risk management activities	(2,946)	12,857	(15,803)
Operating expenses, excluding non-cash compensation expense	(96,707)	(78,964)	(17,743)
Selling, general and administrative, excluding non-cash compensation expense	(19,201)	(15,069)	(4,132)
Segment Adjusted EBITDA	$388,578	$329,025	$59,553

Volumes. NGL production increased primarily due to increased inlet volumes at our La Grange plant as a result of more favorable processing conditions and more production by our customers in the Eagle Ford Shale area in south Texas. The decrease in equity NGL production was primarily due to a higher concentration of volumes billed under fee-based contracts in 2011 as compared to 2010.

Gross Margin. The components of our midstream segment gross margin were as follows:

	Years Ended December 31,		
	2011	2010	Change
Gathering and processing fee-based revenues	$271,065	$226,343	$44,722
Non fee-based contracts and processing	252,755	204,078	48,677
Other	(16,388)	(20,220)	3,832
Total gross margin	$507,432	$410,201	$97,231

Midstream gross margin increased between the periods due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased volumes from production in the Eagle Ford Shale resulted in increased fee-based revenues of $26.4 million in 2011 as compared to 2010. Additionally, increased volumes from the growth of our assets in West Virginia and Louisiana provided an increase in our fee-based margin of $18.4 million in 2011 as compared to 2010.

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- Non fee-based contracts and processing margin. Our non fee-based gross margins increased $48.7 million primarily due to higher NGL prices. The composite NGL price for 2011 was $1.30 per gallon as compared to $1.02 per gallon in 2010. Lower equity NGL production volumes partially offset this increase.
- Other midstream gross margin. The increase in other midstream gross margin was due to increased margin associated with processing where third party processing was utilized. Additionally, we recorded unrealized gains of $2.9 million in 2011 associated with our marketing activities compared to unrealized losses of $12.9 million in 2010. For the years ended December 31, 2011 and 2010, other midstream margin was net of $35.7 million and $40.0 million, respectively, of fees charged by our intrastate transportation systems. These fees were recognized as income by our intrastate transportation and storage segment and have no effect on our consolidated results of operations.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized gains of $2.9 million in 2011 compared to unrealized losses of $12.9 million in 2010 primarily due to a decrease in the volume of hedging activities of our marketing affiliate.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased $17.7 million between the periods primarily due to an increase in maintenance and operating expenses of $7.3 million, an increase in ad valorem taxes of $3.6 million, an increase in employee expenses of $4.5 million and an increase in professional fees of $2.4 million. These increases primarily resulted from new assets placed into service in the Eagle Ford Shale.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased between the periods primarily due to increases in professional fees of $3.8 million and other costs of $2.4 million offset by a decrease in employee costs of $2.1 million.

NGL Transportation and Services

	Years Ended December 31,		
	2011	2010	Change
NGL transportation volumes (Bbls/d)	132,862	—	132,862
NGL fractionation volumes (Bbls/d)	16,475	—	16,475
Revenues	$397,101	$—	$397,101
Cost of products sold	218,283	—	218,283
Gross margin	178,818	—	178,818
Operating expenses, excluding non-cash compensation expense	(39,366)	—	(39,366)
Selling, general and administrative, excluding non-cash compensation expense	(13,325)	—	(13,325)
Adjusted EBITDA related to unconsolidated affiliates	(88)	—	(88)
Adjusted EBITDA attributable to noncontrolling interest	(37,842)	—	(37,842)
Segment Adjusted EBITDA	$88,197	$—	$88,197

We own a controlling interest in Lone Star, which acquired all of the membership interests in LDH on May 2, 2011. Results reflected above represent 100% of those of acquired businesses that are engaged in NGL transportation, storage and fractionation from May 2, 2011 to December 31, 2011.

Gross Margin. The components of our NGL transportation and services segment gross margin were as follows:

	Years Ended December 31		
	2011	2010	Change
Storage revenues	$93,102	$—	93,102
Transportation revenues	32,820	—	32,820
Processing and fractionation revenues	52,840	—	52,840

Other revenues	56	—	56
Total gross margin	$178,818	$—	$178,818

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Retail Propane and Other Retail Propane Related

	Years Ended December 31		
	2011	2010	Change
Retail propane gallons (in thousands)	520,572	554,865	(34,293)
Retail propane revenues	$1,360,653	$1,314,973	$45,680
Other retail propane related revenues	107,429	104,673	2,756
Retail propane cost of products sold	839,127	752,926	86,201
Other retail propane related cost of products sold	21,196	21,816	(620)
Gross margin	607,759	644,904	(37,145)
Unrealized losses on commodity risk management activities	4,359	3,073	1,286
Operating expenses, excluding non-cash compensation expense	(342,950)	(335,224)	(7,726)
Selling, general and administrative, excluding non-cash compensation expense	(46,964)	(43,083)	(3,881)
Segment Adjusted EBITDA	$222,204	$269,670	$(47,466)

Volumes. The combination of weather patterns along with continued customer conservation negatively impacted our retail propane sales volumes. Sales volumes were 34.3 million gallons below the same period last year. The combined average temperatures in our operating areas were consistent with normal average temperatures for 2011 but were approximately 3.3% warmer than the same period in 2010.

Gross Margin. Total gross margin decreased $37.1 million in 2011 compared to 2010 primarily due to a decrease of $4.3 million in retail fuel margins related to a decline in the average gross margin per gallon sold as well as a decrease of $34.9 million due to the volume decrease discussed above. Total gross margin also decreased $1.3 million due to an unfavorable non-cash impact between periods attributable to mark-to-market adjustments on financial instruments used in our commodity price risk management activities. These decreases were slightly offset by a $3.4 million increase in other retail propane related gross profit.

Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses increased primarily due to increases of $8.1 million in net business insurance reserves and claims, $7.2 million in vehicle fuel and repair expenses and $1.3 million in general business taxes. These increases were partially offset by decreases of $4.6 million in performance-based bonus accruals, $2.0 million in employee wages and benefits and $3.2 million in other general operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. The increase in selling, general and administrative expenses in 2011 compared to 2010 was due to increases in allocated overhead expenses of $1.8 million. Other selling, general and administrative expenses also increased $2.1 million due in part to increases in employee wages and benefits.

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Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009 (tabular dollar amounts are expressed in thousands)

Consolidated Results

	Years ended December 31, 2010	2009	Change
Segment Adjusted EBITDA			
Intrastate natural gas transportation and storage	$716,176	$768,934	$(52,758)
Interstate natural gas transportation	220,027	228,705	(8,678)
Midstream	329,025	206,232	122,793
Retail propane and other retail propane related	269,670	270,027	(357)
All other	5,990	3,492	2,498
Total Segment Adjusted EBITDA	1,540,888	1,477,390	63,498
Depreciation and amortization	(343,011)	(312,803)	(30,208)
Interest expense, net of interest capitalized	(412,553)	(394,274)	(18,279)
Gains on non-hedged interest rate derivatives	4,616	39,239	(34,623)
Income tax expense	(15,536)	(12,777)	(2,759)
Non-cash compensation expense	(27,180)	(24,032)	(3,148)
Allowance for equity funds used during construction	28,942	10,557	18,385
Unrealized gains (losses) on commodity risk management activities	(78,300)	29,980	(108,280)
Impairment of investments in affiliates	(52,620)	—	(52,620)
Losses on disposal of assets	(5,043)	(1,564)	(3,479)
Proportionate share of unconsolidated affiliates' interest, depreciation and allowance for equity funds used during construction	(22,499)	(22,331)	(168)
Other, net	(482)	2,157	(2,639)
Net income	$617,222	$791,542	$(174,320)

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased due to the completion of expansion projects.

Interest Expense. Interest expense increased primarily due to the issuance of $1.0 billion of senior notes in April 2009 and Transwestern's issuance of $350.0 million of senior notes in December 2009, a portion of the proceeds from which were used to repay borrowings that had been accruing interest at a lower rate. Interest expense is presented net of capitalized interest and allowance for debt funds used during construction, which totaled $16.3 million and $15.0 million in 2010 and 2009, respectively.

Gains on Non-Hedged Interest Rate Derivatives. The gains on non-hedged interest rate swaps in 2009 resulted from an increase in the index rate prior to settlement. The gains on non-hedged interest rate derivatives in 2010 reflect the gains recognized on swaps entered into during the period.

Income Tax Expense. The increase in income tax expense between the periods was primarily due to increases in taxable income within our subsidiaries that are taxable corporations, in addition to an increase in amounts recorded for the Texas margins tax resulting from increased operating income.

Non-Cash Compensation Expense. The increase in non-cash compensation expense was due to an increase in the number of restricted unit awards outstanding, as well as an increase in the grant-date fair value of such awards due to increases in the trading price of ETP common units.

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction increased during 2010 primarily due to construction on the Tiger pipeline, which was placed in service in December 2010.

Unrealized Gain (Losses) on Commodity Risk Management Activities. See discussion of the unrealized gain (loss) on commodity risk management activities included in the discussion of segment results below.

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Impairment of Investments in Affiliates. In 2010, in conjunction with the transfer of our interest in MEP on May 26, 2010, we recorded a non-cash charge of approximately $52.6 million to reduce the carrying value of our interest to its estimated fair value.

Losses on Disposal of Assets. The increase in losses from the disposal of assets primarily resulted from a retirement of pad gas in 2010 in our Bammel storage facility.

Proportionate Share of Unconsolidated Affiliates' Interest, Depreciation and Allowance for Equity Funds Used During Construction. Amounts reflected in 2010 and 2009 include our proportionate share of such amounts attributable to our 50% interest in MEP, for which we transferred substantially all of our interest in May 2010.

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2010	2009	Change
Natural gas transported (MMBtu/d)	12,251,457	12,254,168	(2,711)
Revenues	$3,290,905	$2,391,544	$899,361
Cost of products sold	2,381,397	1,393,295	988,102
Gross margin	909,508	998,249	(88,741)
Unrealized losses on commodity risk management activities	62,370	24,387	37,983
Operating expenses, excluding non-cash compensation expense	(194,955)	(199,806)	4,851
Selling, general and administrative, excluding non-cash compensation expense	(63,454)	(56,866)	(6,588)
Adjusted EBITDA related to unconsolidated affiliates	2,707	2,970	$(263)
Segment Adjusted EBITDA	$716,176	$768,934	(52,758)

Volumes. We experienced a decrease in incremental business due to less favorable basis differentials primarily between the West and East Texas market hubs in 2010 which was offset by an increase in volumes transported under long-term contracts.

Gross Margin. The components of our intrastate transportation and storage segment gross margin were as follows:

	Years Ended December 31,		
	2010	2009	Change
Transportation fees	$594,405	$639,034	$(44,629)
Natural gas sales and other	110,002	91,879	18,123
Retained fuel revenues	143,606	137,840	5,766
Storage margin, including fees	61,495	129,496	(68,001)
Total gross margin	$909,508	$998,249	$(88,741)

Our margin decreased due to the net impact of the following factors:

- The average transportation rate decreased approximately $0.01/MMBtu in 2010 as compared to 2009, which resulted in a decrease in transportation fees of $44.6 million. The lower rate was primarily caused by a decrease of $0.15/MMBtu in the average spot price differential between West and East Texas market hubs from $0.28/MMBtu in 2009 compared to $0.13/MMBtu in 2010.
- From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $40.0 million in 2010 compared to $60.7 million in 2009. The decrease of $20.7 million between periods was primarily due to a reduction in the amount of capacity utilized by our marketing affiliate.
- Margin from natural gas sales and other activity increased $18.1 million in 2010 as compared to 2009 primarily due to more favorable margins on gas sales and favorable impacts from system optimization activities. The margin from the natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation

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activities, and gains and losses on derivatives used to hedge net retained fuel. Excluding derivatives related to storage, in 2010, we had unrealized losses of $13.3 million compared to unrealized gains of $20.9 million in 2009.

- Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Although retention volumes were lower in 2010 compared to 2009, retention revenue increased $5.8 million due to more favorable pricing. Our average retention price for physical gas we retained in 2010 was $4.20/MMBtu compared to $3.54/MMBtu in 2009.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2010	2009	Change
Withdrawals from storage natural gas inventory (MMBtu)	39,784,446	23,305,452	16,478,994
Margin on physical sales	$68,661	$12,113	$56,548
Settlements of derivatives	1,517	177,949	(176,432)
Realized margin on natural gas inventory transactions	70,178	190,062	(119,884)
Fair value adjustments	(57,157)	14,630	(71,787)
Unrealized gains (losses) on derivatives	8,842	(111,171)	120,013
Margin recognized on natural gas inventory, including related derivatives	21,863	93,521	(71,658)
Revenues from fee-based storage	40,674	39,779	895
Other costs	(1,042)	(3,804)	2,762
Total storage margin	$61,495	$129,496	$(68,001)

The decrease in our storage margin was principally driven by reductions in mark-to-market adjustments associated with the decline in spreads between the spot and forward prices prior to withdrawing natural gas from our Bammel storage facility. We also experienced lower realized margins from our withdrawals due to weaker market conditions in 2010 than in 2009.

Unrealized Losses on Commodity Risk Management Activities. Unrealized losses totaled $62.4 million in 2010 compared to losses of $24.4 million in 2009. The $38.0 million variance was primarily related to our commercial optimization activities, for which we recorded mark to market losses of $13.3 million in 2010 compared to mark to market gains of $20.9 million in 2009 and for which the gross margin impact for the related hedged item was recorded upon settlement.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased between the periods primarily due to a $14.3 million decrease in the cost of natural gas consumed from $55.9 million in 2009 to $41.6 million in 2010. This decrease was principally due to a decrease in consumption volumes as compared to the prior year. In addition, we experienced a decrease in electricity costs of approximately $4.6 million. Offsetting these decreases were increases in pipeline maintenance expenses of approximately $8.6 million, increases in ad valorem taxes of $2.8 million resulting from increased property values and additions, and increases in environmental expenses of $1.6 million due to a pipeline rupture in 2010. Additionally, we experienced a net increase of $1.1 million in various other operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses increased primarily due to increased employee-related costs (including allocated overhead expenses) of approximately $19.5 million which was primarily attributable to accrued bonus expense, for which none was recorded in 2009. Offsetting the increase was a decrease in professional fees of approximately $12.8 million between periods.

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Interstate Transportation

	Years Ended December 31,		
	2010	2009	Change
Natural gas transported (MMBtu/d)	1,616,762	1,661,785	(45,023)
Natural gas sold (MMBtu/d)	23,760	18,531	5,229
Revenues	$292,419	$270,213	$22,206
Operating expenses, excluding non-cash compensation expense	(83,740)	(59,343)	(24,397)
Selling, general and administrative, excluding non-cash compensation expense	(20,171)	(22,123)	1,952
Adjusted EBITDA related to unconsolidated affiliates	31,519	39,958	(8,439)
Segment Adjusted EBITDA	$220,027	$228,705	$(8,678)

Volumes. Average daily transportation volumes on Transwestern decreased in 2010 as compared to 2009 primarily due to less favorable market conditions for transporting natural gas to West delivery points. Tiger pipeline was placed into service in December 2010, and incremental volumes for Tiger pipeline during December 2010 averaged 138,058 MMBtu/d.

Revenues. Revenues increased primarily due to an increase of $20.3 million in Transwestern's operational gas sales due to increased gas prices. In addition, transportation revenues increased approximately $1.9 million in 2010 compared to 2009 due to incremental revenues of $10.2 million for the Tiger pipeline since being placed into service in December 2010. The incremental revenue from Tiger pipeline was slightly offset by a decrease in transportation revenues on Transwestern pipeline as a result of the decreased volumes discussed above.

Operating Expenses, Excluding Non-Cash Compensation Expense. The increase in operating expenses reflects a $9.6 million increase in ad valorem and other taxes primarily related to increased property values for the Phoenix pipeline expansion, a $5.2 million increase related to gas imbalance activities, a $2.1 million increase in right-of-way and rent expenses, and a $2.0 million increase in maintenance project expenses.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Selling, general and administrative expenses decreased primarily due to lower employee-related costs and allocated overhead.

Adjusted EBITDA Related to Unconsolidated Affiliates. We transferred substantially all of our interest in MEP to ETE on May 26, 2010, prior to which we held a 50% joint venture interest in MEP. Amounts reflected primarily represent our proportionate share of such amounts recorded by MEP.

Midstream

	Years Ended December 31,		
	2010	2009	Change
NGLs produced (Bbls/d)	51,144	46,640	4,504
Equity NGLs produced (Bbls/d)	19,301	17,355	1,946
Revenues	$3,169,314	$2,441,160	$728,154
Cost of products sold	2,759,113	2,116,279	642,834
Gross margin	410,201	324,881	85,320
Unrealized (gains) losses on commodity risk management activities	12,857	(8,730)	21,587
Operating expenses, excluding non-cash compensation expense	(78,964)	(68,989)	(9,975)
Selling, general and administrative, excluding non-cash compensation expense	(15,069)	(40,930)	25,861
Segment Adjusted EBITDA	$329,025	$206,232	$122,793

Volumes. NGL production increased in 2010 as compared to 2009 primarily due to increased inlet volumes at our Godley processing plant as a result of more production by our customers in the North Texas area and favorable processing conditions. These factors also contributed to an increase in our equity NGL volumes.

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Gross Margin. The components of our midstream segment gross margin were as follows:

	Years Ended December 31,		
	2010	2009	Change
Gathering and processing fee-based revenues	$226,343	$169,814	$56,529
Non fee-based contracts and processing	204,078	141,061	63,017
Other	(20,220)	14,006	(34,226)
Total gross margin	$410,201	$324,881	$85,320

Midstream gross margin increased between the periods due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased volumes in our North Texas system resulted in increased fee-based margin of $24.1 million. Additionally, increased volumes resulting from our recent acquisitions and other growth capital expenditures located in Louisiana and West Virginia provided an increase of $27.9 million in our margin.
- Non fee-based contracts and processing margins. Non fee-based gross margin increased $63.0 million primarily due to higher processing volumes at our Godley plant and more favorable NGL prices. In 2010, the composite NGL price of $1.02 per gallon increased $0.25 per gallon from $0.77 per gallon in 2009.
- Other midstream gross margin. As a result of our marketing activities, we recorded unrealized gains in 2009 of $8.7 million associated with transport capacity that was contracted with our intrastate transportation and storage segment. In 2010, we recorded unrealized losses of $12.9 million associated with our marketing activities that were partially offset by realized gains. In 2010 and 2009, other midstream margin is net of $40.0 million and $60.7 million, respectively, of fees charged by our intrastate transportation systems. These fees are recognized as income by our intrastate transportation and storage segment and have no effect on our consolidated results of operations.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our marketing affiliate recorded unrealized losses of $12.9 million in 2010 compared to unrealized gains of $8.7 million in 2009. This variance was primarily the result of the timing of hedging activities for transportation capacity and the physical volumes being hedged.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased primarily due to an increase in maintenance expense of $2.7 million, an increase in plant operating expenses of $2.0 million, and a net increase in other operating expenses of $5.3 million resulting from increased volumes on our systems and processing/treating facilities.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased primarily due to a decrease in professional fees of $18.5 million, of which $10.0 million related to a FERC settlement in 2009, and a net decrease of $7.4 million in other expenses primarily due to lower employee-related costs (including allocated overhead expenses).

Retail Propane and Other Retail Propane Related

	Years Ended December 31		
	2010	2009	Change
Retail propane gallons (in thousands)	554,865	568,315	(13,450)
Retail propane revenues	$1,314,973	$1,190,523	$124,450
Other retail propane related revenues	104,673	102,060	2,613
Retail propane cost of products sold	752,926	574,854	178,072
Other retail propane related cost of products sold	21,816	21,148	668
Gross margin	644,904	696,581	(51,677)
Unrealized (gains) losses on commodity risk management activities	3,073	(45,637)	48,710
Operating expenses, excluding non-cash compensation expense	(335,224)	(340,757)	5,533
Selling, general and administrative, excluding non-cash compensation expense	(43,083)	(40,160)	(2,923)
Segment Adjusted EBITDA	$269,670	$270,027	$(357)

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Volumes. Sales volumes were negatively impacted by the timing and geographic distribution of temperature patterns due to an abrupt end to the 2009-2010 heating season in the eastern United States and the continued customer conservation resulting from the lingering effects of the economic recession, which slowed certain normal seasonal deliveries. These negative impacts more than offset the favorable impact to sales volumes resulting from the colder than normal weather in certain areas of our operations. In 2010, the combined average temperatures in our operating areas were approximately 3.3% colder than normal as compared to weather which was approximately 4.1% colder than normal in 2009.

Gross Margin. Total gross margin decreased primarily due to a decrease of $48.7 million attributable to the mark-to-market adjustment for our financial instruments used in our commodity price risk management activities, as discussed below, and also a decrease of approximately $13.5 million resulting from the decrease in volumes discussed above. The decrease in gross margin was offset by an approximate $8.6 million favorable impact from increases in the average margin per gallon sold in 2010 over 2009 and a $1.9 million increase in other gross profit.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Prior to April 2009, our financial instruments used to hedge our customer prebuy programs 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. The propane margins in 2009 include unrealized gains of $45.6 million on these contracts. In comparison, the remaining contracts under mark-to-market accounting resulted in unrealized losses of $3.1 million in 2010.

Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses decreased primarily due to decreases of $4.2 million in compensation and benefits expense, $5.7 million in performance-based bonus accruals and $2.2 million due to a reduction in net business insurance reserves and claims. These decreases were partially offset by an increase in our vehicle fuel expenses due to the increase in fuel costs between periods and a slight increase in other general operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. The increase in selling, general and administrative expenses was primarily due to increased administrative expense allocations.

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 facilities, for which we expect to spend between $800 million and $900 million in 2012;
- growth capital expenditures for our NGL transportation and services segment of between $1.3 billion and $1.5 billion in 2012, for which we expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $350 million and $400 million; and
- maintenance capital expenditures of between $130 million and $140 million during 2012, 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 related to NGL transportation and services, including amounts expected to be funded by our joint venture partner related to its 30% interest in Lone Star.

We do not expect to make any growth capital expenditures in 2012 related to our interstate transportation segment.

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. 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.

As discussed in Note 3 to our consolidated financial statements included in this report, we entered into the Amended Citrus Merger Agreement on July 19, 2011. In January 2012, we issued senior notes to fund substantially all of the cash portion of the purchase price. We also intend to issue sufficient additional equity to maintain its investment grade credit rating and to use the proceeds

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from such equity issuances to repay other indebtedness and fund capital expenditures. In addition, we may enter into other acquisitions, including the potential acquisition of new pipeline systems.

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.

We recently amended our revolving credit facility to, among other things, increase the capacity from $2.0 billion to $2.5 billion and extend the maturity date to 2016. As of December 31, 2011, in addition to $106.8 million of cash on hand, we had available capacity under our revolving credit facility (the "ETP Credit Facility") of $2.16 billion. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2012; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

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 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 a 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, 2011

Cash provided by operating activities in 2011 was $1.34 billion and net income was $697.2 million. The difference between net income and cash provided by operating activities in 2011 consisted of non-cash items totaling $486.1 million and changes in operating assets and liabilities of $165.7 million. The non-cash activity in 2011 consisted primarily of depreciation and amortization of $430.9 million and non-cash compensation expense of $37.5 million.

Year Ended December 31, 2010

Cash provided by operating activities in 2010 was $1.20 billion and net income was $617.2 million. The difference between net income and cash provided by operating activities in 2010 consisted of non-cash items totaling $416.9 million, changes in operating assets and liabilities of $125.2 million, interest rate swap termination proceeds of $26.5 million and distributions received from our affiliates that exceeded our equity in earnings by $20.9 million. The non-cash activity in 2010 consisted primarily of depreciation and amortization of $343.0 million, non-cash compensation expense of $28.4 million, and a non-cash impairment of
$52.6 million on our investment in MEP. This impairment was incurred prior to our transfer of substantially all of our investment in MEP to ETE on May 26, 2010. These amounts are partially offset by the allowance for equity funds used during construction of $28.9 million.

Year Ended December 31, 2009

Cash provided by operating activities in 2009 was $826.9 million and net income was $791.5 million. The difference between net income and cash provided by operating activities in 2009 consisted of non-cash items totaling $355.5 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 $320.7 million.

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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, 2011

Cash used in investing activities in 2011 was $3.55 billion. Total capital expenditures (excluding the allowance for equity funds used during construction) were $1.42 billion including changes in accruals of $93.3 million. Growth capital expenditures in 2011, before changes in accruals, were $1.16 billion for our midstream, intrastate transportation and storage and NGL segments, $180.6 million for our interstate transportation segment, and $35.9 million for our retail propane and all other segments. We also incurred $134.2 million in maintenance expenditures, of which $76.6 million related to our midstream, intrastate transportation and storage and NGL segments, $30.5 million related to our interstate transportation segment, and $27.1 million to our retail propane and all other segments. In addition, in 2011 we paid cash for acquisitions of $1.97 billion, primarily for the LDH Acquisition, and made net advances to our joint ventures of $200.5 million.

Year Ended December 31, 2010

Cash used in investing activities in 2010 was $1.49 billion. Total capital expenditures (excluding the allowance for equity funds used during construction) were $1.35 billion including changes in accruals of $37.6 million. Growth capital expenditures in 2010, before changes in accruals, were $429.8 million for our midstream and intrastate transportation and storage segments, $824.6 million for our interstate transportation segment, and $34.5 million for our retail propane and all other segments. We also incurred $99.3 million in maintenance expenditures, of which $50.7 million related to our midstream and intrastate transportation and storage segments, $20.5 million related to our interstate transportation segment, and $28.0 million to our retail propane and all other segments. In addition, in 2010 we paid cash for acquisitions of $177.9 million.

Year Ended December 31, 2009

Cash used in investing activities in 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 transportation and storage segments, $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 related 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 in 2009 exceeded the cash we paid by $30.4 million.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods based on increases in the number of Common Units outstanding.

Following is a summary of financing activities by period:

Year Ended December 31, 2011

Cash provided by financing activities was $2.27 billion in 2011. We received $1.47 billion in net proceeds from Common Unit offerings, including $96.3 million under our equity distribution program (see Note 6 to our consolidated financial statements). Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, acquisitions, and capital contributions to joint ventures, as well as for general partnership purposes. In 2011, we had a net increase in our debt level of $1.38 billion primarily due to our issuance of $1.50 billion of senior notes in May 2011 to partially fund the LDH Acquisition. We also received $645.3 million of capital contributions from noncontrolling interest related to the LDH Acquisition. In 2011, we paid distributions of $1.16 billion to our partners.

Year Ended December 31, 2010

Cash provided by financing activities was $272.9 million in 2010. We received $1.15 billion in net proceeds from Common Unit offerings, including $239.3 million under our equity distribution program (see Note 6 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, as well as for general partnership purposes. In 2010, we had a net increase in our debt level of $192.8 million primarily due to borrowings to fund capital expenditures and to fund capital contributions to joint ventures,

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partially offset by the use of proceeds from our Common Unit offerings. In 2010, we paid distributions of $1.07 billion to our partners.

Year Ended December 31, 2009

Cash provided by financing activities was $495.2 million in 2009. We received $936.3 million in net proceeds from Common Unit offerings, including $81.5 million under our equity distribution program (see Note 6 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. In 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 5 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 Transwestern issued $350.0 million 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. In 2009, we paid distributions of $957.3 million to our partners.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows (in thousands):

	Pro Forma December 31, 2011 [1]	Actual at December 31, 2011	2010
ETP Senior Notes	$7,800,000	$6,550,000	$5,050,000
Transwestern Senior Unsecured Notes	870,000	870,000	870,000
HOLP Senior Secured Notes	—	71,314	103,127
Revolving credit facilities	314,438	314,438	402,327
Other long-term debt	—	10,345	9,541
Unamortized discounts	(21,407)	(15,457)	(12,074)
Fair value adjustments related to interest rate swaps	11,647	11,647	17,260
Total debt	8,974,678	7,812,287	6,440,181
Less: current maturities	(108,000)	(424,117)	(35,265)
Long-term debt, less current maturities	$8,866,678	$7,388,170	$6,404,916

(1) Pro forma amounts reflect December 31, 2011 actual amounts, as adjusted for (i) the closing of the Propane Transaction in January 2012 and assumption by AmeriGas of the debt related to the Propane Business, (ii) the January 2012 senior notes offering described below, and (iii) the 2012 tender offer as described below.

The terms of our consolidated indebtedness and that of our Operating Companies are described in more detail below and in Note 5 to our consolidated financial statements.

January 2012 Senior Notes Offering

In January 2012, we completed a public offering of $1.0 billion aggregate principal amount of our 5.2% Senior Notes due February 1, 2022 and $1.0 billion aggregate principal amount of our 6.5% Senior Notes due February 1, 2042. We expect to use the net proceeds of approximately $1.979 billion from this offering to fund the cash portion of the purchase price, or $1.895 billion, of the Citrus Acquisition and for general partnership purposes. If we do not consummate the Citrus Acquisition on or before April 17, 2012, or if the Citrus Merger Agreement is terminated at any time on or before such date, we must redeem the notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

2012 Tender Offer

In January 2012, we announced a cash tender offer for up to $750 million aggregate principal amount of specified series of the ETP Senior Notes. The tender offer consisted of two separate offers: an Any and All Offer and a Maximum Tender Offer. The senior notes described below were repurchased under the Any and All Offer and Maximum Tender Offer for a total cost of $885.9 million.

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In the Any and All Offer, we offered to purchase, under certain conditions, any and all of our 5.65% Senior Notes due August 1, 2012, at a fixed price. Pursuant to the Any and All Offer, we purchased $292.0 million in aggregate principal amount on January 19, 2012.

In the Maximum Tender Offer, we offered to purchase, under certain conditions, certain series of outstanding ETP Senior Notes at a fixed spread over the index rate. Pursuant to this tender offer, on February 7, 2012, we purchased $200.0 million aggregate principal amount of our 9.7% Senior Notes due March 15, 2019, $200.0 million aggregate principal amount of our 9.0% Senior Notes due April 15, 2019 and $58.1 million aggregate principal amount of our 8.5% Senior Notes due April 15, 2014.

Put Option

The holders of our 9.7% Senior Notes due March 15, 2019 have the right to require us to repurchase all or a portion of such notes on March 15, 2012 at a purchase price equal to 100% of the principal amount (par value) of the notes tendered. Subsequent to the settlement of the Maximum Tender Offer on February 7, 2012, as discussed above, $400.0 million aggregate principal amount of such notes remains outstanding. The current market value of these remaining outstanding notes is significantly higher than the principal amount, making a repurchase at par value uneconomic by the holder. However, if such a repurchase were to occur, we would intend to refinance any amounts paid on a long-term basis.

ETP Credit Facility

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.

On October 27, 2011, we amended and restated the ETP Credit Facility to, among other things, (i) allow for borrowings of up to $2.5 billion; (ii) extend the maturity date from July 20, 2012 to October 27, 2016 (which may be extended by one year with lender approval); (iii) allow for an increase in the size of the credit facility to $3.75 billion (subject to obtaining lender commitments for the additional borrowing capacity); and (iv) to adjust the interest rates and commitment fees to current market terms. Following this amendment and based on our current ratings, the interest margin for LIBOR rate loans is 1.50% and the commitment fee for unused borrowing capacity is 0.25%.

We use the ETP Credit Facility to provide temporary financing for our growth projects, as well as for general partnership purposes. We typically repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term notes offerings. The timing of borrowings depends on the Partnership's activities and the cash available to fund those activities. The repayments of amounts outstanding under the ETP Credit Facility depend on multiple factors, including market conditions and expectations of future working capital needs, and ultimately are a financing decision made by management. Therefore, the balance outstanding under the ETP Credit Facility may vary significantly between periods. We do not believe that such fluctuations indicate a significant change in our liquidity position, because we expect to continue to be able to repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term note offerings.

As of December 31, 2011, we had $314.4 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $2.16 billion taking into account letters of credit of $25.6 million. The weighted average interest rate on the total amount outstanding as of December 31, 2011 was 1.78%.

Debt Covenants

The agreements relating 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 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; and
- enter into restrictive agreements;

The credit agreement relating to the ETP Credit Facility also contains a financial covenant that provides that the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1 as of the end of each quarter, with a permitted increase to 5.5 to 1 during a Specified Acquisition Period, as defined in the ETP Credit Facility.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of all or substantially all assets and the payment of dividends and specify a maximum debt to capitalization ratio.

We are required to assess compliance quarterly and were in compliance with all requirements, limitations, and covenants related to debt agreements as of December 31, 2011. We plan to fund our working capital needs and growth capital expenditures 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 — Construction of new pipeline 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 future projects will result in an increase in our level of indebtedness in future quarters, we also expect that the incremental cash flow from the projects will allow us to satisfy the financial covenants related to our existing debt in 2012.

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

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2011, excluding amounts related to our Propane Business, which was contributed to AmeriGas in January 2012 (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$7,734,438	$400,000	$788,000	$1,189,438	$5,357,000
Interest on long-term debt (a)	5,517,107	506,815	932,525	788,517	3,289,250
Payments on derivatives	117,020	74,778	42,242	—	—
Purchase commitments (b)	19,336	19,336	—	—	—
Operating lease obligations	237,364	19,795	35,178	32,547	149,844
Totals (c)	$13,625,265	$1,020,724	$1,797,945	$2,010,502	$8,796,094

(a) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2011. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2011. To the extent interest rates change, our contractual obligations for interest payments will change. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further discussion.

(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, 2011 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.

(c) Excludes non-current deferred tax liabilities of $125.9 million due to uncertainty of the timing of future cash flows for such liabilities.

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
Year Ended December 31, 2011	November 4, 2011	November 14, 2011	$0.89375
	August 5, 2011	August 15, 2011	0.89375
	May 6, 2011	May 16, 2011	0.89375
	February 7, 2011	February 14, 2011	0.89375
Year Ended December 31, 2010	November 8, 2010	November 15, 2010	$0.89375
	August 9, 2010	August 16, 2010	0.89375
	May 7, 2010	May 17, 2010	0.89375
	February 8, 2010	February 15, 2010	0.89375
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

On January 25, 2012, we declared a cash distribution for the three months ended December 31, 2011 of $0.89375 per Common Unit, or $3.575 annualized. We paid this distribution on February 14, 2012 to Unitholders of record at the close of business on February 7, 2012.

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

	Years Ended December 31,		
	2011	2010	2009
Limited Partners:			
Common Units	$762,350	$676,798	$629,263
Class E Units	12,484	12,484	12,484
General Partner Interest	19,603	19,524	19,505
Incentive Distribution Rights	421,888	375,979	350,486
Total distributions declared	$1,216,325	$1,084,785	$1,011,738

New Accounting Standards

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment ("ASU 2011-08"), which simplified how entities test goodwill for impairment. ASU 2011-08 gives entities the option, under certain circumstances, to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for

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determining whether further impairment testing is necessary. ASU 2011-08 is effective for fiscal years beginning after December 15, 2011, and early adoption is permitted. We adopted and applied this standard to our annual impairment tests performed for certain of our reporting units during the year ended December 31, 2011. There was no impact to our financial position or results of operations as a result of the adoption of this standard.

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, 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 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 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, NGL 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, 2011 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, 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, 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 and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale. 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.

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) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. Excess fuel retained after consumption is typically valued at market prices.

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.

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.

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 prices 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 mark-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 prices 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.

NGL storage and pipeline transportation revenues are recognized when services are performed or products are delivered, respectively. Fractionation and processing revenues are recognized when product is either loaded into a truck or injected into a third party pipeline, which is when title and risk of loss pass to the customer.

In our natural gas compression business, revenue is recognized for compressor packages and technical service jobs using the completed contract method which recognizes revenue upon completion of the job. Costs incurred on a job are deducted at the time revenue is recognized.

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,

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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. These contracts consist primarily of futures and swaps.

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 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. 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 Instruments. 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. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

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. We adopted ASU 2011-08 during the year ended December 31, 2011. This standard allows us to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary.

In order to test for recoverability when performing a quantitative impairment test, 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.

Property, Plant and Equipment. 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

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directly related to the 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 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. We have determined that we are obligated by contractual or regulatory 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, 2011 or 2010 because the settlement dates were indeterminable. We will record an asset retirement obligation in the periods in which management 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 8 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" 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," "estimate," "intend "believe," "may," "will" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected.

Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our 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 NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- 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 NGLs;

- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;

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- 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;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- 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 “Item 1A. Risk Factors” in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

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.

The United States Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the “CFTC”), the SEC, and other regulators to promulgate rules and regulations implementing the new legislation. In December 2011, the CFTC extended relief from certain swap regulation provisions of the Legislation until July 16, 2012. The CFTC issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. It is not possible at this time to predict when the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is

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uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.
Commodity Price Risk
For certain of our activities, we are exposed to market risks related to the volatility of natural gas and NGL prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and over-the-counter 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 reduce 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 forward financial contracts at a price sufficient to cover our 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 natural gas in excess of consumption, a portion of volumes purchased at the wellhead from producers, and location price differentials related to the transportation of natural gas. Additionally, during the fourth quarter of 2011 we used derivatives for trading purposes.
- 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.
- Our propane segment permitted customers to guarantee the propane delivery price for the next heating season. We executed fixed sales price contracts with our customers and entered into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. We used propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

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 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 cost of products sold in our consolidated statements 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 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.
We attempt to maintain balanced positions 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.

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The table below summarizes our commodity-related financial derivative instruments and fair values 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. Dollar amounts are in thousands.

	December 31, 2011			December 31, 2010		
	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						
Natural Gas:						
Basis Swaps IFERC/NYMEX - Trading (1)	(151,260,000)	$(22,582)	$2,593	—	$—	$—
Basis Swaps IFERC/NYMEX - Non-Trading	(61,420,000)	4,024	266	(38,897,500)	(2,334)	304
Swing Swaps IFERC	92,370,000	(1,072)	138	(19,720,000)	(2,086)	2,228
Fixed Swaps/Futures	797,500	(4,301)	145	(2,570,000)	(11,488)	1,176
Forward Physical Contracts	(10,672,028)	(13)	1,118	—	—	—
Options — Calls	—	—	—	(3,000,000)	62	7
Propane:						
Forwards/Swaps	38,766,000	(4,122)	5,290	1,974,000	275	258
Fair Value Hedging Derivatives						
Natural Gas:						
Basis Swaps IFERC/NYMEX - Non-Trading	(28,752,500)	(808)	181	(28,050,000)	722	322
Fixed Swaps/Futures	(45,822,500)	70,761	14,048	(39,105,000)	8,599	16,837
Cash Flow Hedging Derivatives						
Natural Gas:						
Fixed Swaps/Futures	—	—	—	(210,000)	232	93
Options — Puts	3,600,000	6,435	933	26,760,000	10,545	7,125
Options — Calls	(3,600,000)	(12)	13	(26,760,000)	4,812	1,565
Propane:						
Forwards/Swaps	—	—	—	32,466,000	6,589	4,196

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information 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 net income 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

As of December 31, 2011, we had $314.4 million of floating rate debt outstanding under our revolving credit facility. A hypothetical change of 100 basis points would result in a change to interest expense of $3.1 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

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We had the following interest rate swaps outstanding as of December 31, 2011 (dollars in thousands), none of which are designated as hedges for accounting purposes:

Term	Type [(1)]	Notional Amount Outstanding December 31, 2011	December 31, 2010
May 2012[(2)]	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	$350,000	$—
August 2012[(2)]	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	500,000	400,000
July 2013[(2)]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	300,000	—
July 2018	Pay a floating rate plus a spread of 4.01% and receive a fixed rate of 6.70%	500,000	500,000

(1) As of December 31, 2011, floating rates are based on 3-month LIBOR.
(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on non-hedged interest rate derivatives) of approximately $82.7 million as of December 31, 2011. For the $500 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows (swap settlements) of $5.0 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

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 or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream and power generation 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. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements starting on page F-1 of this report are incorporated by reference.

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

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

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Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2011.

Management’s Report on Internal Control 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 Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer 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”).

On May 2, 2011, ETP-Regency Midstream Holdings, LLC (“ETP-Regency LLC”), a joint venture owned 70% by the Partnership and 30% by Regency Energy Partners LP (“Regency”), acquired all of the membership interest in LDH Energy Asset Holdings LLC (“LDH”), from Louis Dreyfus Highbridge Energy LLC (“Louis Dreyfus”). Subsequent to closing, ETP-Regency LLC was renamed Lone Star NGL LLC and LDH was renamed Lone Star NGL Asset Holdings LLC ("Lone Star Holdings"). Management has acknowledged that it is responsible for establishing and maintaining a system of internal controls over financial reporting for Lone Star Holdings. We are in the process of integrating Lone Star Holdings, and we therefore excluded Lone Star Holdings from our December 31, 2011 assessment of the effectiveness of internal control over financial reporting. Lone Star Holdings had total assets of $2.21 billion and third party revenue of $361.5 million from May 2, 2011 to December 31, 2011 included in our consolidated financial statements as of and for the year ended December 31, 2011. The impact of the acquisition of LDH has not materially affected and is not expected to materially affect our internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient controls over the substantive results of our financial reporting throughout this integration process.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2011, 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, 2011, 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 (Management's Report). Our responsibility is to express an opinion on Energy Transfer Partners, L.P.'s internal control over financial reporting based on our audit. Our audit of, and opinion on, Energy Transfer Partners, L.P.'s internal control over financial reporting does not include internal control over financial reporting of Lone Star NGL Asset Holdings LLC (formerly LDH Energy Asset Holdings LLC), a consolidated subsidiary, whose financial statements reflect total assets and revenues constituting 14 and 5 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2011. As indicated in Management's Report, LDH Energy Asset Holdings LLC was acquired during 2011 and therefore, management's assertion on the effectiveness of Energy Transfer Partners, L.P.'s internal control over financial reporting excluded internal control over financial reporting of Lone Star NGL Asset Holdings LLC (formerly LDH Energy Asset Holdings LLC).

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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 22, 2012 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 22, 2012

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Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control 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

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 six current directors include ETP LLC's Chief Executive Officer and ETP LLC's President and Chief Operating Officer.

From January 1, 2011 until June 30, 2011, our Board of Directors was comprised of nine persons, seven of whom qualified as "independent" under the NYSE's corporate governance standards. In order to serve on the special committee of the ETE Board, on and effective as of June 30, 2011, each of Messrs. Davis, Turner and Albin resigned from the ETP Board. Of our current six directors, we have determined that Messrs. Byrne, Collins, Glaske, and Grimm 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 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 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.

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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.

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 annual report. In 2011, our CEO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE 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 407 (d)(5) of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee members Paul E. Glaske and Bill W. Byrne qualified as Audit Committee financial experts during 2011. A description of the qualifications of Mr. Glaske and Mr. Byrne may be found elsewhere in this Item 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 auditing standards, 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, Michael K. Grimm and Bill W. Byrne currently serve on the Audit Committee and Mr. Glaske serves as the chairman of the 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 and Bill W. Byrne serve as the members of the Compensation Committee and Mr. Grimm serves as the chairman of the Compensation

Committee. Our General Partner has determined that both Messrs. Byrne and Grimm are "independent" (as that term is defined in the applicable NYSE corporate governance standards).

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

- annually review and approve goals and objectives relevant to compensation of the CEO, if applicable;
- 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, if applicable, 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.

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. Amendments to, or waivers from, the Code of Business Conduct and Ethics will be available on our website and reported as may be required under SEC rules. Any technical, administrative or other non-substantive amendments to the Code of Business Conduct and Ethics may not be posted.

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. The Chairman of each of our Audit and Compensation Committee alternate as the presiding director of such meetings.

We have established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of our General Counsel at Energy Transfer Partners, L.P., 3738 Oak Lawn Avenue, Dallas, Texas 75219 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of the General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of February 22, 2012. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	56	Chief Executive Officer and Chairman of the Board of Directors
Marshall S. (Mackie) McCrea, III	52	President, Chief Operating Officer and Director
Martin Salinas, Jr.	40	Chief Financial Officer
Thomas P. Mason	55	Vice President, General Counsel and Secretary
Bill W. Byrne	82	Director
Paul E. Glaske	78	Director
Ted Collins, Jr.	73	Director
Michael K. Grimm	57	Director

Messrs. Warren and McCrea also serve as directors of ETE's general partner.
In order to serve on the special committee of the ETE Board of Directors, on and effective June 30, 2011, Messrs. Ray C. Davis, K. Rick Turner and David R. Albin resigned from the ETP Board of Directors.
On April 14, 2011 Mr. William G. Powers announced his retirement as President of Propane Operations and the Partnership announced the appointment of Paul Grady as the new President of Propane Operations, effective July 1, 2011. On January 12, 2012, we completed the contribution of our propane business to AmeriGas and, in connection with this transaction, Paul Grady became an officer of AmeriGas and is therefore no longer an executive officer of our General Partner.
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.
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 extensive 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.
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.
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 more than 25 years.
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.
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. Currently, 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

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opportunities.
Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. He is also chairman and chief executive officer of Patriot Resources Partners LLC and a director of CLL Global Research Foundation. 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 EOG Resources, and its predecessors, Enron Oil and Gas Company, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quasar Petroleum Company. In February 2011, Mr. Collins was elected as a director of Oasis Petroleum, Inc. and has served on its audit committee and nominating and governance committee since May 2011. Mr. Collins has served as a director of our General Partner since August 2004. Mr. Collins is a past President of the Permian Basin Petroleum Association, the Permian Basin Landmen's Association, the Petroleum Club of Midland and has served as Chairman of the Midland Wildcat Committee since 1984. 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. In addition, 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.
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. Currently, Mr. Grimm is also President of Rising Star Energy Development Company and a co-CEO of RSP Permian, which is active in the drilling and developing of West Texas Permian Basin oil reserves. Prior to the formation of the first Rising Star companies, 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 13 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, Dallas Wildcat Committee, and Fort Worth Wildcatters. Mr. Grimm has served as a director of our General Partner since December 2005 and is a member of the Audit Committee and chairman of the Compensation Committee. 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.
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 combination of the operations of ETC OLP and HOLP 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.
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 6 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act 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, 2011, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner.

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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 as "our General Partner." As of December 31, 2011 ETE owned 100% of our General Partner and approximately 22% of our outstanding units. All of our employees are employed by and receive employee benefits from our 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
- Robert P. (Paul) Grady, President of Propane Operations.

Mr. Grady was President of Propane Operations as of December 31, 2011. On January 12, 2012, we completed the contribution of our propane business to AmeriGas and, in connection with this transaction, Mr. Grady became an officer of AmeriGas and is therefore no longer an executive officer of our General Partner.
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 each executive's compensation should be incentive-based and that executives' 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 marketplace and balanced between short and long-term performance. Our General Partner believes this balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of our named executive officers to the success of the Partnership 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 on increasing the market price of our publicly traded units and to increase the cash distribution we pay to our Unitholders. Since 2008, our equity awards have primarily been in the form of restricted unit awards that vest over a specified time period, with substantially all of these 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 our named 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. We directly pay 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, 2011, we paid 100% of the compensation of the executive officers of our General Partner as we represent the only business currently managed by our General Partner.

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

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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.

Components of Executive Compensation

For the year ended December 31, 2011, 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).

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. Periodically, the Compensation Committee engages a third-party consultant to provide market information for compensation levels at peer companies in order to assist the Compensation Committee in its determination of compensation levels for our executive officers. Most recently, the Compensation Committee engaged Mercer Consulting Services (“Mercer”) during the year ended December 31, 2010 to assist in the determination of compensation levels for our senior management. The results of this study were utilized to determine long-term incentive awards and bonuses during 2011 and 2010. The consultant provided an analysis of compensation for senior executives at the following 15 companies in the energy industry, comprised primarily of midstream and exploration and production companies:

- Enterprise Products Partners L.P.
- Plains All American Pipeline, L.P.
- CenterPoint Energy, Inc.
- The Williams Companies, Inc.
- Sempra Energy
- Kinder Morgan Energy Partners, L.P.
- ONEOK Partners, L.P.
- Enbridge Energy Partners, L.P.
- Sunoco Logistics Partners L.P.
- Atmos Energy Corporation
- El Paso Corporation
- Spectra Energy Partners, LP
- Targa Resources Partners LP
- NuStar Energy L.P.
- Southern Union Company

The compensation analysis provided by Mercer covered annual salary, annual cash bonus and long-term incentive arrangements for the senior executives of these companies. The Compensation Committee utilized the information provided by Mercer to compare the levels of base salary, annual bonus and long-term equity incentives at these other companies with those of our named executive officers to ensure that compensation of our named executive officers is competitive with the compensation for executive officers of these other companies. The Compensation Committee did not attempt to benchmark the base salary, annual bonus or long-term equity incentives to any percentage of, or numerical average of, the compensation levels at these other companies. Mercer did not provide any non-executive compensation services for the Partnership during 2011 or 2010.

Base Salary. As discussed above, the base salaries of our named executive officers are determined by the Compensation Committee after taking into account the recommendations of Mr. Warren. For 2011, the Compensation Committee approved an increase of

5% to Mr. McCrea's annual base salary. The Compensation Committee determined that such an increase was warranted based on the factors described below under "-Annual Bonus." The Compensation Committee did not increase the salaries of Messrs. Salinas and Mason for 2011. The Compensation Committee approved an increase of 6.7% in Mr. Grady's annual base salary upon his promotion to President of Propane Operations effective July 1, 2011. In 2010, the Compensation Committee approved increases in the annual base salaries of Messrs. McCrea, Salinas and Mason of 3% each from their prior annual base salaries. The Compensation Committee determined that such increases in annual base salary were warranted in light of their individual performance and levels of responsibility related to the management of the Partnership.

Annual Bonus. In addition to base salary, the Compensation Committee makes a determination whether to award our named executive officers, other than our CEO (who has voluntarily elected to forgo any annual bonuses), discretionary annual cash bonuses following the end of the year. These discretionary bonuses, if awarded, are intended 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 such year. In this regard, the Compensation Committee takes into account whether the Partnership achieved or exceeded its internal EBITDA budget for the year, which is approved by the board of directors of our General Partner as discussed below, as an important element in making its determinations with respect to annual bonuses. The Compensation Committee also considers the recommendation of our CEO in determining the specific annual cash bonus amounts for each of the other named executive officers. The Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and the Compensation Committee does not utilize any formulaic approach to determine annual bonuses.

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 the Partnership's EBITDA for a calendar year. In general, the Compensation Committee believes that Partnership performance at or above the internal EBITDA budget would support bonuses to our named executive officers ranging from 100% to 120% 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.

In February 2012, the Compensation Committee approved cash bonuses relating to the 2011 calendar year to Messrs. McCrea, Salinas, and Mason of $750,000, $400,000, and $750,000, respectively. In approving the cash bonuses for Messrs. McCrea, Salinas, and Mason, the Compensation Committee took into account the achievement by the Partnership of approximately 95% of its internal EBITDA budget of $1.838 billion for 2011 as well as the individual performances of these individuals with respect to promoting the Partnership's financial, strategic and operating objectives for 2011. With respect to Mr. McCrea, the Compensation Committee noted the extraordinary individual performance of Mr. McCrea with respect to the successful development of several significant internal growth projects, including (i) natural gas gathering, processing and transportation projects related to the Eagle Ford Shale play in south Texas with estimated capital expenditures in excess of $1.4 billion, (ii) a major gathering and processing project related to the Woodford Shale play with estimated capital expenditures of approximately $360 million, (iii) several NGL pipeline projects with estimated capital expenditures of approximately $350 million and (iv) additional NGL pipeline and fractionation projects through our Lone Star NGL joint venture with Regency with estimated capital expenditures of approximately $1.6 billion. With respect to Mr. Salinas, the Compensation Committee took note of his key roles during 2011 in (i) managing the financial analysis related to the significant projects and transactions discussed above and below, (ii) coordinating the successful offering of ETP common units that collectively raised approximately $1.47 billion in net proceeds during 2011, (iii) orchestrating the successful arrangement of a $3.7 billion bridge credit facility as financing for the cash portion of the Southern Union merger, and (iv) effectively managing the financial reporting function for ETE and ETP. With respect to Mr. Mason, the Compensation

Committee took note of his key roles in (i) negotiating the formation of the Lone Star joint venture with Regency and the related negotiation of the acquisition by the Lone Star joint venture of the NGL transportation and storage business of Louis Dreyfus for approximately $1.98 billion, (ii) the negotiation of the acquisition by ETE of Southern Union in a transaction valued at approximately $9.4 billion at the time of its announcement, (iii) the negotiation of the contribution of ETP's retail propane business to AmeriGas in a transaction valued at approximately $2.9 billion at the time of its announcement and (iv) the effective managing of the legal functions for ETE and ETP. In November 2011, the Compensation Committee approved a cash bonus for Mr. Grady of $275,000 with respect to the fiscal year of our propane operations. With respect to Mr. Grady, the Compensation Committee took note of his effective management of the retail propane segment, which accounted for approximately 13% of our total Adjusted EBITDA for 2011, despite challenges faced relating to unusual weather patterns and customer conservation measures.

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 awards 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

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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 certain 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.

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. This change resulted from the Compensation Committee's determination that vesting based on continued employment, rather than the satisfaction of performance objectives, was more generally prevalent with companies in the energy industry. In December 2011, the Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas and Mason of 50,000 units, 25,000 units, and 40,000 units, respectively. In May 2011, the Compensation committee approved a grant award to Mr. McCrea of 136,000 units. All of these unit awards provide 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.

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. In the case of the unit award to Mr. McCrea, the Compensation Committee took into account the significant achievements of Mr. McCrea discussed under the caption "-Annual Bonus," and the fees expected to be realized from those projects. The magnitude of the unit award to Mr. McCrea, along with the five-year vesting of this unit award, was also intended by the Compensation committee to provide a significant incentive to Mr. McCrea to remain with the Partnership and continue to develop successful commercial projects.

In April 2011, upon Mr. Grady's appointment as President of Propane Operations, the Compensation Committee approved a grant of unit awards to Mr. Grady of 5,000 units. These unit awards to Mr. Grady were forfeited in January 2012, in connection with the contribution of the propane operations to AmeriGas.

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. The Compensation Committee did not accelerate the vesting of unit awards in 2011.

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 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 ETE or ETP 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 2011. Messrs. McCrea and Salinas had unvested rights related to ETE units of 84,000 and 96,000, respectively, as of December 31, 2011. All ETE units previously awarded to Mr. Mason had vested as of December 31, 2011.

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. Employees may elect to defer up to 100% of their eligible compensation after applicable taxes, as limited under the Internal Revenue Code. We make a matching contribution that is not 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 is fully vested and non-forfeitable at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement. 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 named 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. Our 2004 Unit Plan provides for immediate vesting of all unvested unit awards in the event of a change in control, as defined in the plan. In addition, our 2008 Incentive Plan provides the Compensation Committee with the discretion to provide for immediate vesting of all unvested unit awards in the event of a change of control, as defined in the plan. Please refer to "— Compensation Tables— Potential Payments upon a Terminated or Change of Control" for additional information.

Deferred Compensation Plan. Effective January 1, 2010, we adopted a deferred compensation plan ("DC Plan"). The DC Plan permits eligible highly compensated employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other designated distribution.

Under the DC Plan, each year eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, ETP may make annual discretionary matching contributions to participants' accounts; however, we have not made any discretionary contributions to participants' accounts and currently have no plans to make any discretionary contributions to participants' accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings (or losses) based on hypothetical investment fund choices made by the participants among available funds.

Participants may also elect to have their accounts distributed in one lump sum payment or in annual installments over a period of 3 or 5 years upon retirement, and in a lump sum upon other termination. Upon a change in control (as defined in the DC Plan) of ETP, all DC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the DC Plan's normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement.

Risk Assessment Related to our Compensation Structure. We believe our compensation plans and programs for our named executive officers, as well as our 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 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 named executive officers receive a cash bonus based on our achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership's success. 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.

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 not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore 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 7 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm, Byrne and Davis served on the Compensation Committee during 2011. During 2011, none of the members of the committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company’s board of directors. In addition, neither Mr. Grimm nor Mr. Byrne are former employees of ours or any of our subsidiaries. Mr. Davis is associated with business entities with which we have

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relationships. See “Item 13. Certain Relationships and Related Transactions, and Director Independence.” Mr. Davis's service on the Compensation Committee ceased upon his resignation from the board of directors of our General Partner effective June 30, 2011.

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 ETP. 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

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	Salary ($)	Bonus ($) (1)	Equity Awards ($) (2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Kelcy L. Warren (4)	2011	$ 3,240	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,240
Chief Executive	2010	2,766	—	—	—	—	—	—	2,766
Officer	2009	2,289	—	—	—	—	—	—	2,289
Martin Salinas, Jr.	2011	360,532	400,000	1,128,500	—	—	(6,462)	25,020	1,907,590
Chief Financial	2010	356,058	480,000	999,600	—	—	7,648	27,250	1,870,556
Officer	2009	350,000	—	847,062	—	—	—	31,293	1,228,355
Marshall S. (Mackie) McCrea, III	2011	615,049	750,000	9,542,520	—	—	—	12,972	10,920,541
President and Chief	2010	538,077	729,500	13,455,000	—	—	—	12,250	14,734,827
Operating Officer	2009	500,000	—	883,000	—	—	—	12,250	1,395,250
Thomas P. Mason	2011	432,901	750,000	1,805,600	—	—	—	32,590	3,021,091
Vice President,	2010	427,513	482,530	999,600	—	—	—	34,990	1,944,633
General Counsel and Secretary	2009	420,240	—	802,912	—	—	—	41,005	1,264,157
Robert (Paul) Grady (5)	2011	387,500	275,000	266,900	—	—	745	13,540	943,685
President of Propane Operations									

(1) The discretionary cash bonus amounts for our named executive officers for 2011 reflect cash bonuses approved by the Compensation Committee in February 2012 that are expected to be paid in March 2012.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. See Note 7 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2011 in this column include (i) contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $9,567 for Mr. Salinas and $12,250 each for Messres. McCrea, Mason and Grady, (ii) expenses paid by us for housing for Messrs. Salinas and Mason near our executive office in Dallas and (iii) the dollar value of life insurance premiums paid for the benefit of the named executive officers. Vesting in 401(k) contributions occurs immediately.

(4) Mr. Warren voluntarily determined that his salary would be reduced to $1.00 per year (plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits). He does not accept a cash bonus or any equity awards under the equity incentive plans.

(5) Mr. Grady was promoted to President of Propane Operations in July 2011. The 2011 amounts reflect his compensation for the entire year.

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Grants of Plan-Based Awards Table

Name	Grant Date	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Unit)	Grant Date Fair Value of Unit Awards (1)
Kelcy L. Warren	N/A	—	—	$—	$—
Martin Salinas, Jr.	12/20/2011	25,000	—	—	1,128,500
Marshall S. (Mackie) McCrea, III	5/2/2011	136,000	—	—	7,285,520
	12/20/2011	50,000	—	—	2,257,000
Thomas P. Mason	12/20/2011	40,000	—	—	1,805,600
Robert P. (Paul) Grady	4/20/2011	5,000	—	—	266,900

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 7 to our consolidated financial statements.

We do not have any non-equity incentive plans.

Narrative Disclosure to Summary Compensation Table and Grants of the Plan-Based Awards Table

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, nonqualified deferred compensation earnings, and 401(k) plan contributions can be found in the compensation discussion and analysis that precedes these tables.

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Outstanding Equity Awards at Year-End Table

		Unit Awards	
Name	Grant Date (1)	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 ($) (2)
Kelcy L. Warren	N/A	—	$—
Martin Salinas, Jr.	12/20/2011	25,000	1,146,250
	12/15/2010	16,000	733,600
	12/15/2009	11,512	527,825
	12/22/2008	8,000	366,800
	12/5/2007	1,200	55,020
Marshall S. (Mackie) McCrea, III	12/20/2011	50,000	2,292,500
	5/2/2011	108,800	4,988,480
	1/14/2011	200,000	9,170,000
	12/15/2009	12,000	550,200
	12/22/2008	8,000	366,800
	12/5/2007	4,400	201,740
Thomas P. Mason	12/20/2011	40,000	1,834,000
	12/15/2010	16,000	733,600
	12/15/2009	10,912	500,315
	12/22/2008	8,000	366,800
	10/17/2008	20,000	917,000
	12/5/2007	3,600	165,060
Robert P. (Paul) Grady	4/20/2011	4,000	183,400
	12/15/2010	4,320	198,072
	12/15/2009	3,274	150,113
	12/22/2008	2,400	110,040
	2/28/2008	8,000	366,800
	12/5/2007	1,200	55,020

(1) With the exception of Mr. Mason's unit awards granted October 17, 2008, which vest ratably on each anniversary of the grant date thorough 2013, the unit awards outstanding as of December 31, 2011 reflected in the table above ratably vest in December of each year through 2016 for awards granted in 2011, through 2015 for awards granted in 2010, through 2014 for awards granted in 2009, through 2013 for awards granted in 2008, and through 2012 for awards granted in 2007. All of Mr. Grady's outstanding unit awards were forfeited in January 2012 in connection with the contribution of ETP's propane business to AmeriGas.

(2) Market value was computed as the number of unvested awards as of December 31, 2011 multiplied by the closing price of our Common Units on December 31, 2011.

The amounts above do not include the equity awards granted to certain 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.

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Option Exercises and Units Vested Table

Name	Unit Awards Number of Units Acquired on Vesting (#) (1)	Value Realized on Vesting ($) (1)
Kelcy L. Warren	—	$—
Martin Salinas, Jr.	13,037	572,129
Marshall S. (Mackie) McCrea, III	89,600	3,932,096
Thomas P. Mason	25,237	1,079,956
Robert P. (Paul) Grady	9,571	$460,563

(1) Amounts presented represent the number of unit awards vested during 2011 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.

We have not issued option awards.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($)
Kelcy L. Warren	$—	$—	$—	$—	$—
Martin Salinas, Jr.	67,151	—	(6,462)	—	117,204
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Robert P. (Paul) Grady	116,250	—	745	—	430,304

The aggregate earnings reflected above for Mr. Salinas are included in his total compensation in the "Summary Compensation Table." The aggregate balance reflected above for Mr. Salinas also includes earnings of $7,648 which were reported in his total compensation for 2010.

A description of the key provisions of the Partnership's deferred compensation plan can be found in the compensation discussion and analysis above.

Potential Payments upon a Termination or Change of Control

Equity Awards. As discussed in our Compensation Discussion and Analysis above, any unvested equity awards granted pursuant to the 2004 Unit Plan will automatically become vested upon a change of control. Assuming that a change of control occurred on December 31, 2011, the fair value of the unvested awards granted pursuant to the 2004 Unit Plan as of December 31, 2011 were $421,820 for Mr. Salinas, $568,540 for Mr. McCrea, $2,182,460 for Mr. Mason and $421,820 for Mr. Grady, respectively. In addition, Messrs. Salinas and McCrea hold unvested rights to receive ETE units granted by McReynolds Energy Partners, L.P. that would become immediately vested in connection with a change in control. Assuming that a change of control occurred on December 31, 2011, the fair value of these awards would have been $3,895,680 for Mr. Salinas and $3,408,720 for Mr. McCrea. Although any unvested equity awards granted under the 2008 Incentive Plan may also become vested upon a change of control at the discretion of the Compensation Committee, this discussion assumes a scenario in which the Compensation Committee does not exercise such discretion.

While any individual award agreement may contain a modified definition, a change in control is generally defined under the 2004 Unit Plan as the occurrence of any of the following events: (i) ETP GP ceases to be our general partner; (ii) 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 ETP GP; (iii) the sale of all or substantially all of ETP's assets (other than to any affiliate of ETE); or (iv) a liquidation or dissolution of ETP. For purposes of the rights with respect to ETE units granted by McReynolds Energy Partners, L.P., a change in control means a "change in control" as defined in the 2004 Unit Plan, but a change in control will also be considered to have occurred if any single party, other than Kelcy Warren, acquires either: (a) more than 90% of the then-outstanding limited partner units of ETE; or (b) more than 51% of the ownership of LE GP, LLC. Under the 2008 Incentive Plan, a "change of control" is generally defined as the occurrence of one or more of the following events: (1) any person or group becomes the beneficial owner of 50 percent or more of our voting power or voting securities; (2) the complete liquidation of either ETP LLC, ETP GP, or us; (3) the sale of all

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or substantially all of ETP GP's or our assets to anyone other than us, ETP GP or one of our affiliates; or (4) a person other than ETP LLC, ETP GP or one of their affiliates becomes our general partner.

Deferred Compensation Plan. As discussed in our Compensation Discussion and Analysis above, all amounts under the DC Plan (other than discretionary credits) are immediately 100% vested. Upon a change in control (as defined in the DC Plan), distributions from the DC Plan would be made in accordance with the DC Plan's normal distribution provisions. A change in control is generally defined in the DC Plan as any change in control event within the meaning of Treasury Regulation Section 1.409A-3(i)(5).

Director Compensation Table

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. In 2011, 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. In connection with the Citrus Acquisition, the Board of Directors appointed Messrs. Byrne, Glaske and Grimm to serve on the Conflicts Committee to address potential conflicts of interest in that transaction. For their service on the Conflicts Committee, which met 11 times during 2011, Messrs. Byrne, Glaske and Grimm received additional compensation of $5,000 per Conflicts Committee meeting for the Chairman of the Conflicts Committee and $2,500 per Conflicts Committee meeting for the members of the Conflicts Committee. Employee directors, including Messrs. Warren and McCrea, 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 unvested 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 approximately $50,000 divided by the fair market value of our Common Units on the date of grant. These ETP Common Units vest over three years at one-third per year.

The compensation paid to the non-employee directors of our General Partner in 2011 is reflected in the following table.

Name	Fees Paid in Cash ($) (1)	Unit Awards ($) (2)	All Other Compensation ($)	Total ($)
Bill W. Byrne	$94,500	$45,659	$—	$140,159
Paul E. Glaske	123,300	45,659	—	168,959
Ted Collins, Jr.	40,000	45,659	—	85,659
Michael K. Grimm	94,600	45,659	—	140,259
Ray C. Davis (3)	38,575	22,283	—	60,858
K. Rick Turner (3)	33,222	22,283	—	55,505
David R. Albin (3)	165,889	—	—	165,889

(1) Fees paid in cash are based on amounts paid during the period. Fees paid to Mr. Albin during 2012 include amounts owed from prior years.

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

(3) Messrs. Davis, Turner and Albin resigned from the board effective June 30, 2011. All outstanding awards to these individuals were vested upon resignation.

As of December 31, 2011, Messrs. Byrne, Glaske, Collins and Grimm each had 1,623 unit awards outstanding.

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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, 2011:

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	2,563,709	$—	$2,788,181
Equity compensation plans not approved by security holders	—	—	—
Total	2,563,709	$—	2,788,181

Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 15, 2012, regarding the beneficial ownership of our securities by certain beneficial owners, each director and named executive officer of our General Partner and all directors and executive officers of our General Partner as a group. 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	*	
	Marshall S. (Mackie) McCrea , III	110,581	*	
	Martin Salinas, Jr.	27,848	*	
	Thomas P. Mason	48,543	*	
	Bill W. Byrne	164,997	*	
	Paul E. Glaske	96,366	*	
	Michael K. Grimm	19,350	*	
	Ted Collins, Jr.	97,553	*	
	All Directors and Executive Officers as a Group (8 Persons)	586,345	*	
	ETE (4)	50,226,967	22.2	%
Class E Units	Heritage Holdings, Inc. (5)	8,853,832	100	%

*Less than 1%

(1) The address for Messrs. Mason, Salinas and 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 Mr. McCrea is 800 E. Sonterra Blvd., San Antonio, Texas 78258. The address for ETE is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Messrs. Byrne, Grimm, Collins and Glaske 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 Exchange Act. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct

the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers within sixty (60) days.

(3) Due to the ownership by certain officers and directors of the general partner of ETE of equity interests in ETE (either directly

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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 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) 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 members of LE GP, LLC are Ray C. Davis and Kelcy L. Warren.

(5) The Partnership indirectly owns 100% of the common stock of Heritage Holdings, Inc.

Pursuant to a pledge and security agreement between ETE and Wells Fargo Bank, National Association, as the administrative agent under ETE's revolving credit facility, all of ETE's interest in Energy Transfer Partners, L.L.C. and Energy Transfer Partners GP, L.P., and the 50,226,967 ETP common units owned by ETE, are pledged as collateral for the benefit of the lenders under such credit facility.

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's board of directors makes the determinations as to whether there exists a related-party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its fiduciary duties to the Unitholders. The Partnership Agreement 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.

ETE owns directly and indirectly the general partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights and 50,226,967 ETP Common Units.

We have a shared services agreement in which we provide various general and administrative services for ETE. See discussion in Note 11 to our consolidated financial statements.

We have an operating lease agreement with the former owners of Energy Transfer Group, L.L.C. ("ETG"), which we acquired in 2009. These former owners include Mr. Warren and Mr. Davis. See discussion in Note 11 to our consolidated financial statements.

With respect to the related party transaction with ETG, the Conflicts Committee of ETP met numerous times prior to the consummation of the transaction to discuss the terms of the transaction. The committee made the determination that the sale of ETG to ETP was fair and reasonable to ETP and that the terms of the operating lease between ETP and the former owners of ETG are fair and reasonable to ETP.

On September 1, 2011, Regency exercised its option to acquire our remaining 0.1% interest in MEP for approximately $1.2 million in cash.

We received $17.1 million, $6.3 million and $0.5 million in management fees from ETE for the provision of various general and administrative services for ETE's benefit for the years ended December 31, 2011, 2010 and 2009, respectively. The increase recorded in the years ended December 31, 2011 and 2010 were the result of increased service fees related to the provision of various general and administrative services for Regency which was acquired by ETE in 2010. In addition, the management fees for the year ended December 31, 2011 include the provision of various general and administrative services for Regency. For the year ended December 31, 2011 we recorded from Regency $6.6 million for reimbursement of various general and administrative expenses incurred by us.

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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,	
	2011	2010
Audit fees[1]	$1,966,500	$2,125,795
Audit related fees[2]	372,000	—
Tax fees[3]	9,553	—
All other fees	—	—
Total	$2,348,053	$2,125,795

(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 SEC and services related to the audit of our internal control over financial reporting.

(2) Includes fees in 2011 for attestation engagements of subsidiary entities in connection with the contribution of the Partnership's retail propane operations to AmeriGas Partners, L.P. in January 2012.

(3) Includes fees in 2011 related to state and local tax consultation and training.

Pursuant to the charter of the Audit Committee, the Audit Committee is 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 Audit 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 F-1.
(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 22, 2012
/s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer (Principal Financial and Accounting Officer)	February 22, 2012
/s/ Bill W. Byrne Bill W. Byrne	Director	February 22, 2012
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	President, Chief Operating Officer and Director	February 22, 2012
/s/ Paul E. Glaske Paul E. Glaske	Director	February 22, 2012
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	February 22, 2012
/s/ Michael K. Grimm Michael K. Grimm	Director	February 22, 2012

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INDEX TO EXHIBITS

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

	Exhibit Number	Description
(14)	2.1	Redemption and Exchange Agreement dated as of May 10, 2010 by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P.
(59)	2.2	Purchase Agreement, dated March 22, 2011, among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC and Louis Dreyfus Highbridge Energy LLC, Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(69)	2.3	Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011.
(70)	2.4	Amendment No. 1, dated December 1, 2011, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011.
(66)	2.5	Amendment No. 1, dated as of September 14, 2011, to the Amended and Restated Agreement and Plan of Merger, dated as of July19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(71)	2.6	Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(13)	3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009.
(1)	3.2	Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(44)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(56)	3.6	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C.
(57)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
(57)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
(57)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
(21)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(22)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(28)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.

(30)	4.9	Third Supplemental Indenture dated as of July 29, 2005 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(32)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(32)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.

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	Exhibit Number	Description
(42)	4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(33)	4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(51)	4.15	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(48)	4.16	Seventh Supplemental Indenture dated December 23, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(23)	4.16.1	Eighth Supplemental Indenture dated April 7, 2009, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(35)	4.17	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(65)	4.18	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(45)	10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower, and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents, and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC, as senior managing agents, and other lenders party hereto.
(43)	+ 10.6.6	Amended and Restated 2004 Unit Plan.
(49)	+ 10.6.8	Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan.
(58)	+ 10.6.9	Energy Transfer Partners Deferred Compensation Plan.
(24)	10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers, and La Grange Acquisition, L.P., as Buyer.
(25)	10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(34)	10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(36)	10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(37)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(42)	10.54	Fourth Amended and Restated Credit Agreement dated as of August 31, 2006 between and among Heritage Operating L.P., as the Borrower, and the Banks parties thereto, as lenders, and Bank of Oklahoma, National Association, as administrative agent and joint lead arranger for

		the Banks, JPMorgan Chase Bank, N.A., as syndication agent for the Banks, and J.P. Morgan Securities Inc., as joint lead arranger for the Banks.
(44)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(44)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(44)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(26)	10.56.1	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.

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	Exhibit Number	Description
(60)	10.57	Guarantee, dated as of March 22, 2011, by Energy Transfer Partners, L.P. in favor of Louis Dreyfus Highbridge Energy LLC.
(61)	10.58	Assumption, Contribution and Indemnification Agreement, dated as of March 22, 2011, by and between Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(62)	10.59	Amended and Restated Energy Transfer Partners, L.P. Midstream Bonus Plan dated April 18, 2011
(63)	10.60	Amended and Restated Limited Liability Company Agreement of ETP-Regency Midstream Holdings, LLC, dated May 2, 2011.
(64)	10.61	Term Loan Agreement dated as of July 28, 2011, by and among Fayetteville Express Pipeline LLC, The Royal Bank of Scotland plc, as administrative agent, and certain other agents and lenders party thereto.
(67)	10.62	Amendment No. 1, dated as of September 14, 2011, to Second Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and Southern Union Company.
(68)	10.63	Second Amended and Restated Credit Agreement dated as of October 27, 2011 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and an LC Issuer, the other lenders party thereto and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc., as Joint Lead Arrangers and Joint Book Managers.
(*)	12.1	Computation of Ratio of Earnings to Fixed Charges.
(*)	21.1	List of Subsidiaries.
(*)	23.1	Consent of Grant Thornton LLP.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2011 and December 31, 2010; (ii) our Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010 and 2009; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2011, 2010 and 2009; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.
\+ Denotes a management contract or compensatory plan or arrangement.

(1) Incorporated by reference the same numbered Exhibit to the 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 filed August 23, 2000.
(9) Incorporated by reference to Exhibit 10.16.3 to the Registrant's Form 10-Q for the quarter ended May 31, 2000.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 2000.
(11) Incorporated by reference to Exhibit 10.2.7 to the Registrant's Form 10-Q for the quarter ended February 28, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2001.
(13) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K filed July 29, 2009.
(14) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K/A filed June 2, 2010.
(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 filed 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.
(20) Incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005.
(21) Incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 19, 2005.
(22) Incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on April 7, 2009.
(23) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed February 1, 2005.
(24) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005.
(25) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 14, 2009.
(26) 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.
(31) Incorporated by reference to the same numbered Exhibit to the Registrant's Form S-3 filed August 9, 2006.
(32) Incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 25, 2006.
(33) Incorporated by reference to Exhibit 3.1.10 to the Registrant's Form 8-K filed November 3, 2006.
(34) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 18, 2006.
(35) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed March 3, 2008.
(36) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed September 18, 2006.
(37) Incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed September 18, 2006.
(38) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 2006.
(39) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended June 30, 2008.
(40) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007.
(41) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K filed July 23, 2007.

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(42) Incorporated by reference to Exhibit 4.2 to the Registrant’s Form 8-K filed December 23, 2008.
(43) Incorporated by reference to Exhibit A to the Proxy Statement filed by the Registrant November 21, 2008.
(44) Incorporated by reference to Exhibit 4.2 to the Registrant’s Form 8-K filed March 31, 2008.
(45) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed March 4, 2008.
(46) Incorporated by reference to Exhibit 10.2 to the Registrant’s Form 8-K filed March 4, 2008.
(47) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed November 19, 2009.
(48) Incorporated by reference to Exhibit 10.2 to the Registrant’s Form 8-K filed November 19, 2009.
(49) Incorporated by reference to Exhibit 3.1 to the Registrant’s Form 8-K filed August 10, 2010.
(50) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended March 31, 2010.
(51) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 10-Q for the quarter ended March 31, 2010.
(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.
(56) Incorporated by reference to Exhibit 3.1 to the Registrant’s Form 8-K filed August 10, 2010.
(57) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended March 31, 2010.
(58) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 10-Q for the quarter ended March 31, 2010.
(59) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K/A filed on March 25, 2011.
(60) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K/A filed on March 25, 2011.
(61) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K/A filed on March 25, 2011.
(62) Incorporated by reference to Exhibit 10.5 to the Registrant's Form 10-Q filed on August 8, 2011.
(63) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 2, 2011.
(64) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed August 2, 2011.
(65) Incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed May 12, 2011.
(66) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed September 15, 2011.
(67) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 15, 2011.
(68) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 2, 2011.
(69) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed October 18, 2011.
(70) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed December 7, 2011.
(71) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed July 20, 2011.

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INDEX TO FINANCIAL STATEMENTS
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 (the "Partnership") as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2011, 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 22, 2012 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 22, 2012

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PART I — FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$106,816	$49,540
Marketable securities	1,229	2,032
Accounts receivable, net of allowance for doubtful accounts of $7,651 and $6,409 as of December 31, 2011 and 2010, respectively	568,579	503,129
Accounts receivable from related companies	81,753	53,866
Inventories	306,740	362,058
Exchanges receivable	18,808	21,823
Price risk management assets	11,429	13,706
Other current assets	180,140	115,269
Total current assets	1,275,494	1,121,423
PROPERTY, PLANT AND EQUIPMENT	13,983,888	11,087,468
ACCUMULATED DEPRECIATION	(1,677,522)	(1,286,099)
	12,306,366	9,801,369
ADVANCES TO AND INVESTMENTS IN AFFILIATES	200,612	8,723
LONG-TERM PRICE RISK MANAGEMENT ASSETS	25,537	13,948
GOODWILL	1,219,597	781,233
INTANGIBLE ASSETS, net	331,409	264,690
OTHER NON-CURRENT ASSETS, net	159,601	158,606
Total assets	$15,518,616	$12,149,992

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, 2011	2010
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$401,053	$301,997
Accounts payable to related companies	33,373	27,177
Exchanges payable	17,906	15,451
Price risk management liabilities	79,518	—
Accrued and other current liabilities	629,202	462,560
Current maturities of long-term debt	424,117	35,265
Total current liabilities	1,585,169	842,450
LONG-TERM DEBT, less current maturities	7,388,170	6,404,916
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	42,303	18,338
OTHER NON-CURRENT LIABILITIES	152,550	140,851
COMMITMENTS AND CONTINGENCIES (Note 8)		
EQUITY:		
General Partner	181,646	174,618
Limited Partners:		
Common Unitholders (225,468,108 and 193,212,590 units authorized, issued and outstanding as of December 31, 2011 and 2010, respectively)	5,533,492	4,542,656
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary and reported as treasury units)	—	—
Accumulated other comprehensive income	6,569	26,163
Total partners' capital	5,721,707	4,743,437
Noncontrolling interest	628,717	—
Total equity	6,350,424	4,743,437
Total liabilities and equity	$15,518,616	$12,149,992

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,		
	2011	2010	2009
REVENUES:			
Natural gas sales	$2,536,257	$2,441,685	$2,417,741
NGL sales	1,132,023	598,534	472,874
Gathering, transportation and other fees	1,513,802	1,219,628	1,187,969
Retail propane sales	1,360,653	1,314,973	1,190,524
Other	307,705	310,007	148,187
Total revenues	6,850,440	5,884,827	5,417,295
COSTS AND EXPENSES:			
Cost of products sold	4,189,353	3,599,941	3,122,056
Operating expenses	773,767	707,271	680,893
Depreciation and amortization	430,904	343,011	312,803
Selling, general and administrative	211,609	176,433	173,936
Total costs and expenses	5,605,633	4,826,656	4,289,688
OPERATING INCOME	1,244,807	1,058,171	1,127,607
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(474,113)	(412,553)	(394,274)
Equity in earnings of affiliates	25,836	11,727	20,597
Losses on disposal of assets	(3,188)	(5,043)	(1,564)
Gains (losses) on non-hedged interest rate derivatives	(77,409)	4,616	39,239
Allowance for equity funds used during construction	957	28,942	10,557
Impairment of investments in affiliates	(5,355)	(52,620)	—
Other, net	4,442	(482)	2,157
INCOME BEFORE INCOME TAX EXPENSE	715,977	632,758	804,319
Income tax expense	18,815	15,536	12,777
NET INCOME	697,162	617,222	791,542
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	28,188	—	—
NET INCOME ATTRIBUTABLE TO PARTNERS	668,974	617,222	791,542
GENERAL PARTNER’S INTEREST IN NET INCOME	433,148	387,729	365,362
LIMITED PARTNERS’ INTEREST IN NET INCOME	$235,826	$229,493	$426,180
BASIC NET INCOME PER LIMITED PARTNER UNIT	$1.10	$1.20	$2.53
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	207,245,106	188,077,143	167,337,192
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$1.10	$1.19	$2.53
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	208,154,303	188,717,396	167,768,981

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,		
	2011	2010	2009
Net income	$697,162	$617,222	$791,542
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(37,970)	(35,852)	(10,211)
Change in value of derivative instruments accounted for as cash flow hedges	19,180	59,231	3,182
Change in value of available-for-sale securities	(804)	(4,023)	10,923
	(19,594)	19,356	3,894
Comprehensive income	677,568	636,578	795,436
Less: Comprehensive income attributable to noncontrolling interest	28,188	—	—
Comprehensive income attributable to partners	$649,380	$636,578	$795,436

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
(Dollars in thousands)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
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
Units issued for cash	—	936,337	—	—	936,337
Capital contribution 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)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	25	21,838	—	—	21,863
Other comprehensive income, net of tax	—	—	3,894	—	3,894
Other, net	—	(3,762)	—	—	(3,762)
Net income	365,362	426,180	—	—	791,542
Balance, December 31, 2009	174,884	4,418,017	6,807	—	4,599,708
Redemption of units in connection with MEP Transaction (See Note 11)	(3,700)	(600,124)	—	—	(603,824)
Distributions to partners	(393,252)	(672,750)	—	—	(1,066,002)
Units issued for cash	—	1,152,228	—	—	1,152,228
Capital contribution from General Partner	8,932	—	—	—	8,932
Distributions on unvested unit awards	—	(4,460)	—	—	(4,460)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	25	23,654	—	—	23,679
Other comprehensive income, net of tax	—	—	19,356	—	19,356
Other, net	—	(3,402)	—	—	(3,402)
Net income	387,729	229,493	—	—	617,222
Balance, December 31, 2010	174,618	4,542,656	26,163	—	4,743,437
Distributions to partners	(425,975)	(733,478)	—	—	(1,159,453)
Distributions to noncontrolling interest	—	—	—	(44,736)	(44,736)
Units issued for cash	—	1,466,957	—	—	1,466,957
Capital contributions from noncontrolling interest	—	—	—	645,265	645,265
Issuance of units in acquisitions	—	3,000	—	—	3,000
Distributions on unvested unit awards	—	(7,616)	—	—	(7,616)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	25	30,107	—	—	30,132
Other comprehensive loss, net of tax	—	—	(19,594)	—	(19,594)
Other, net	(170)	(3,960)	—	—	(4,130)
Net income	433,148	235,826	—	28,188	697,162
Balance, December 31, 2011	$181,646	$5,533,492	$ 6,569	$ 628,717	$6,350,424

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,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$697,162	$617,222	$791,542
Reconciliation of net income to net cash provided by operating activities:			
Impairments of investments in affiliate	5,355	52,620	—
Proceeds from termination of interest rate derivatives	—	26,495	—
Depreciation and amortization	430,904	343,011	312,803
Amortization of finance costs charged to interest	9,906	9,548	8,645
Non-cash compensation expense	37,457	28,430	25,282
Losses on disposal of assets	3,188	5,043	1,564
Distributions on unvested awards	(7,616)	(4,460)	(2,673)
Distributions in excess of equity in earnings of affiliates, net	3,075	20,909	3,224
Other non-cash	(735)	(21,743)	7,171
Changes in operating assets and liabilities, net of effects of acquisitions (see Note 2)	165,669	125,208	(320,680)
Net cash provided by operating activities	1,344,365	1,202,283	826,878
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net cash (paid for) received from acquisitions	(1,971,581)	(177,920)	30,367
Capital expenditures (excluding allowance for equity funds used during construction)	(1,416,146)	(1,350,754)	(748,621)
Contributions in aid of construction costs	25,371	13,720	6,453
Advances to affiliates, net	(200,495)	(6,775)	(655,500)
Sale of investment in MEP	1,178	—	—
Proceeds from the sale of assets	9,251	27,881	21,545
Net cash used in investing activities	(3,552,422)	(1,493,848)	(1,345,756)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	6,594,315	1,538,286	3,475,107
Principal payments on debt	(5,217,180)	(1,345,439)	(2,954,737)
Net proceeds from issuance of Limited Partner units	1,466,957	1,152,228	936,337
Capital contribution from General Partner	—	8,932	3,354
Capital contributions from noncontrolling interest	645,265	—	—
Distributions to partners	(1,159,453)	(1,066,002)	(957,255)
Distributions to noncontrolling interest	(44,736)	—	—
Redemption of units	—	(15,083)	—
Debt issuance costs	(19,835)	—	(7,647)
Net cash provided by financing activities	2,265,333	272,922	495,159
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	57,276	(18,643)	(23,719)
CASH AND CASH EQUIVALENTS, beginning of period	49,540	68,183	91,902
CASH AND CASH EQUIVALENTS, end of period	$106,816	$49,540	$68,183

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts, except per unit data, are in thousands)

1. OPERATIONS AND ORGANIZATION:

The consolidated financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries (“Energy Transfer Partners,” the “Partnership,” “we” or “ETP”) presented herein for the years ended December 31, 2011, 2010 and 2009, 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. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through the date the financial statements were issued.

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 assets.

Certain prior period amounts have been reclassified to conform to the 2011 presentation. These reclassifications had no impact on net income or total partners’ capital.

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 described below.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, 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:

- La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“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, New Mexico, Utah, Colorado and West Virginia. Our intrastate transportation and storage operations primarily focus on transporting natural gas in Texas 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, North Texas System, Eagle Ford Shale, and Northern Louisiana assets. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance and Uinta Basins of Colorado and Utah, respectively. ETC OLP also owns a 70% interest in Lone Star NGL LLC ("Lone Star"), which is described in Note 3.
- Energy Transfer Interstate Holdings, LLC (“ET Interstate”), a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern Pipeline Company, LLC (“Transwestern”), a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC Fayetteville Express Pipeline, LLC (“ETC FEP”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.
-

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

- ETC Compression, LLC (“ETC Compression”), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

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- Heritage Operating, L.P. (“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 Energy Partners, L.P. (“Titan”), a Delaware limited partnership also engaged in retail propane operations.

On January 12, 2012, we contributed HOLP and Titan to AmeriGas Partners, L.P. (“AmeriGas”). See Note 3.
Our historical financial statements reflect the following reportable business segments: intrastate natural gas transportation and storage; interstate natural gas transportation; midstream; and retail propane and other retail propane related operations. In addition, our consolidated financial statements now reflect a new NGL transportation and services segment, which primarily consists of Lone Star's operations.

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 operations 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 estimated operating results 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, 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, 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 and NGLs 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.

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) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. Fuel retained for a fee is typically valued at market prices.

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.

NGL storage and pipeline transportation revenues are recognized when services are performed or products are delivered, respectively. Fractionation and processing revenues are recognized when product is either loaded into a truck or injected into a third party pipeline, which is when title and risk of loss pass to the customer.

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.

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.

In our natural gas compression business, revenue is recognized for compressor packages and technical service jobs using the completed contract method which recognizes revenue upon completion of the job. Costs incurred on a job are deducted at the time revenue is recognized.

Regulatory Accounting - 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.

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 that 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 during the period.

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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,		
	2011	2010	2009
Accounts receivable	$2,779	$63,481	$28,431
Accounts receivable from related companies	(27,773)	3,437	(29,042)
Inventories	67,888	14,639	(101,592)
Exchanges receivable	3,015	1,312	22,074
Other current assets	(62,333)	33,201	8,155
Other non-current assets	7,366	5,475	(1,517)
Accounts payable	31,158	(47,905)	(16,024)
Accounts payable to related companies	6,196	(11,594)	4,459
Exchanges payable	2,455	(3,752)	(35,433)
Accrued and other current liabilities	59,753	41,135	(93,399)
Other non-current liabilities	(72)	(203)	1,401
Price risk management assets and liabilities, net	75,237	25,982	(108,193)
Net change in operating assets and liabilities, net of effects of acquisitions	$165,669	$125,208	$(320,680)

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

	Years Ended December 31,		
	2011	2010	2009
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$201,716	$88,441	$46,134
Transfer of MEP joint venture interest in exchange for redemption of Common Units	$—	$588,741	$—
NON-CASH FINANCING ACTIVITIES:			
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$4,166	$2,741	$26,237
Issuance of common units in connection with certain acquisitions	$3,000	$—	$63,339
Capital contributions receivable from General Partner	$—	$—	$8,932
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$475,740	$430,761	$367,924
Cash paid for income taxes	$24,448	$8,606	$15,447

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.

Accounts Receivable

Our midstream, NGL 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.

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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. Management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Our interstate transportation operations establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and consider 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.

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,	
	2011	2010
Natural gas and NGLs, excluding propane	$144,251	$168,378
Propane	86,958	76,341
Appliances, parts and fittings and other	75,531	117,339
Total inventories	$306,740	$362,058

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating certain of these 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 cost of products sold in our consolidated statements of operations.

During 2009, we recorded lower of cost or market adjustments of $54.0 million and fair value adjustments related to our application of fair value hedging of $66.1 million. We did not record lower of cost or market adjustments in 2011 or 2010.

Exchanges

Exchanges consist of natural gas and NGL delivery imbalances (over and under deliveries) with others. These amounts, which are valued at market prices or weighted average market prices pursuant to contractual imbalance agreements, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. These imbalances are generally settled by deliveries of natural gas or NGLs, but may be settled in cash, depending on contractual terms.

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Other Current Assets

Other current assets consisted of the following:

	December 31, 2011	2010
Deposits paid to vendors	$66,231	$52,192
Prepaid and other	113,909	63,077
Total other current assets	$180,140	$115,269

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 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 consolidated statements 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.

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

	December 31, 2011	2010
Land and improvements	$136,021	$102,353
Buildings and improvements (10 to 40 years)	267,561	189,210
Pipelines and equipment (10 to 83 years)	9,174,058	7,897,828
Natural gas and NGL storage facilities (40 years) [1]	789,612	100,909
Bulk storage, equipment and facilities (3 to 83 years)	976,882	736,520
Tanks and other equipment (10 to 30 years)	642,575	623,126
Vehicles (3 to 20 years)	213,731	197,323
Right of way (20 to 83 years)	734,036	612,374
Furniture and fixtures (3 to 10 years)	47,018	40,447
Linepack	57,380	54,156
Pad gas	57,907	57,907
Other (5 to 10 years)	154,952	136,775
Construction work-in-process	732,155	338,540
	13,983,888	11,087,468
Less – Accumulated depreciation	(1,677,522)	(1,286,099)
Property, plant and equipment, net	$12,306,366	$9,801,369

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(1) Includes $682.4 million of natural gas liquids storage facilities acquired in connection with the LDH Acquisition described in Note 3.

We recognized the following amounts of depreciation expense for the periods presented:

	Years Ended December 31,	
	2011	2010
Depreciation expense	$405,957	$322,406
Capitalized interest, excluding AFUDC	$11,431	$2,646

Advances to and Investment in Affiliates

We own interests in a number of related businesses that are accounted for by 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 investment in Fayetteville Express Pipeline LLC ("FEP") by the equity method. Our investment in FEP was $173.3 million as of December 31, 2011 and is reflected in our interstate transportation segment.

Goodwill

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment ("ASU 2011-08"), which simplified how entities test goodwill for impairment. ASU 2011-08 gives entities the option, under certain circumstances, to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. ASU 2011-08 was effective for fiscal years beginning after December 15, 2011, and early adoption was permitted. We adopted and applied this standard to our annual impairment tests performed for certain of our reporting units during the year ended December 31, 2011. There was no material impact to our financial position or results of operations as a result of the adoption of this standard.

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 August 31 for subsidiaries in our intrastate transportation and storage, midstream and retail propane segments and as of December 31 for subsidiaries in our interstate and NGL transportation and services segments and all others. No 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	NGL Transportation and Services	Retail Propane	All Other	Total
Balance, December 31, 2009	$10,327	$98,613	$22,150	$—	$603,975	$10,440	$745,505
Goodwill acquired	—	—	27,329	—	9,131	—	36,460
Other	—	—	23	—	—	(755)	(732)
Balance, December 31, 2010	10,327	98,613	49,502	—	613,106	9,685	781,233
Goodwill acquired	—	—	—	432,026	6,338	—	438,364
Balance, December 31, 2011	$10,327	$98,613	$49,502	$432,026	$619,444	$9,685	$1,219,597

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. A net increase in goodwill of $438.4 million was recorded during the year ended December 31, 2011, primarily due to $432.0 million from the LDH acquisition referenced in Note 3. This additional goodwill is expected to be deductible for tax purposes.

Intangible Assets

Intangible 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.

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Components and useful lives of intangible assets were as follows:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$338,424	$(95,239)	$251,418	$(74,910)
Noncompete agreements (3 to 15 years)	15,431	(7,835)	21,165	(11,888)
Patents (9 years)	750	(201)	750	(118)
Other (10 to 15 years)	1,320	(580)	1,320	(492)
Total amortizable intangible assets	355,925	(103,855)	274,653	(87,408)
Non-amortizable intangible assets –				
Trademarks	79,339	—	77,445	—
Total intangible assets	435,264	(103,855)	352,098	(87,408)

Related to the LDH Acquisition discussed in Note 3, we recorded customer contracts of $81.0 million with useful lives ranging from 3 to 15 years during the year ended December 31, 2011.
Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2011	2010	2009
Reported in depreciation and amortization	$24,362	$20,018	$20,895

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

Years Ending December 31:	
2012	$15,616
2013	11,694
2014	10,569
2015	10,569
2016	10,569

Amortizable intangible assets with a gross carrying amount of approximately $127.7 million as of December 31, 2011 were deconsolidated in January 2012 in connection with the contribution of our propane operations described in Note 3. Amounts reflected above do not include any future amortization related to these deconsolidated assets.
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 August 31. No impairment of intangible assets was required during the periods presented in these consolidated financial statements.

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Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2011	2010
Unamortized financing costs (3 to 30 years)	$46,618	$35,267
Regulatory assets	88,993	92,939
Other	23,990	30,400
Total other non-current assets, net	$159,601	$158,606

Asset Retirement Obligation

We have determined that we are obligated by contractual or regulatory 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, 2011 or 2010 because the settlement dates were indeterminable. We will record an asset retirement obligation in the periods in which management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2011	2010
Interest payable	$142,616	$135,867
Customer advances and deposits	84,300	86,191
Accrued capital expenditures	196,789	87,260
Accrued wages and benefits	67,266	61,587
Taxes payable other than income taxes	77,073	27,067
Income taxes payable	14,422	7,390
Deferred income taxes	61	365
Other	46,675	56,833
Total accrued and other current liabilities	$629,202	$462,560

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 cash and cash equivalents, 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 loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2011 was $8.39 billion and $7.81 billion, respectively. As of December 31, 2010, the aggregate fair value and carrying amount of our debt obligations was $7.21 billion and $6.44 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

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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. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the period ended December 31, 2011, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2011 and 2010 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at December 31, 2011	
		Level 1	Level 2
Assets:			
Marketable securities	$1,229	$1,229	$—
Interest rate derivatives	36,301	—	36,301
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	62,924	62,924	—
Swing Swaps IFERC	15,002	1,687	13,315
Fixed Swaps/Futures	214,572	214,572	—
Options – Puts	6,435	—	6,435
Forward Physical Swaps	699	—	699
Propane – Forwards/Swaps	9	—	9
Total commodity derivatives	299,641	279,183	20,458
Total Assets	$337,171	$280,412	$56,759
Liabilities:			
Interest rate derivatives	$(117,020)	$—	$(117,020)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(82,290)	(82,290)	—
Swing Swaps IFERC	(16,074)	(3,061)	(13,013)
Fixed Swaps/Futures	(148,111)	(148,111)	—
Options – Calls	(12)	—	(12)
Forward Physical Swaps	(712)	—	(712)
Propane — Forwards/Swaps	(4,131)	—	(4,131)
Total commodity derivatives	(251,330)	(233,462)	(17,868)
Total Liabilities	$(368,350)	$(233,462)	$(134,888)

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	Fair Value Total	Fair Value Measurements at December 31, 2010	
		Level 1	Level 2
Assets:			
Marketable securities	$2,032	$2,032	$—
Interest rate derivatives	20,790	—	20,790
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	15,756	15,756	—
Swing Swaps IFERC	1,682	1,562	120
Fixed Swaps/Futures	42,474	42,474	—
Options — Puts	26,241	—	26,241
Options — Calls	75	—	75
Propane – Forwards/Swaps	6,864	—	6,864
Total commodity derivatives	93,092	59,792	33,300
Total Assets	$115,914	$61,824	$54,090
Liabilities:			
Interest rate derivatives	$(18,338)	$—	$(18,338)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(17,372)	(17,372)	—
Swing Swaps IFERC	(3,768)	(3,520)	(248)
Fixed Swaps/Futures	(41,825)	(41,825)	—
Options — Puts	(7)	—	(7)
Options — Calls	(2,643)	—	(2,643)
Total commodity derivatives	(65,615)	(62,717)	(2,898)
Total Liabilities	$(83,953)	$(62,717)	$(21,236)

In conjunction with the MEP Transaction in 2010 (described in Note 11), we adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of our investment in MEP was transferred to ETE. See Note 11.

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.

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 are as follows:

	Years Ended December 31,		
	2011	2010	2009
Shipping and handling costs – recorded in operating expenses	$40,379	$43,321	$55,872

We do not separately charge propane shipping and handling costs to customers.

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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 our Second Amended and Restated Agreement of Limited Partnership (the “Partnership Agreement”).
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, 2011, 2010 and 2009, 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.
The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are generally not subject to federal and state income taxes at the Partnership level.
The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31,		
	2011	2010	2009
Current expense (benefit):			
Federal	$(737)	$507	$(8,851)
State	15,407	8,591	9,662
Total	14,670	9,098	811
Deferred expense:			
Federal	3,718	6,325	11,541
State	427	113	425
Total	4,145	6,438	11,966
Total income tax expense	$18,815	$15,536	$12,777

As of December 31, 2011 and 2010, we had net deferred income tax liabilities of $125.9 million and $119.2 million, respectively, recorded in other non-current liabilities in our consolidated balance sheets. Substantially all of our deferred tax liability relates to property, plant and equipment, including $55.3 million and $49.2 million as of December 31, 2011 and 2010, respectively, and basis differences associated with our Class E Units of $72.2 million and $70.2 million as of December 31, 2011 and 2010, respectively. As of December 31, 2011 and 2010 we had deferred income tax liabilities of $0.1 million and $0.4 million, respectively, recorded in accrued and other liabilities in our consolidated balance sheet.

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Accounting for Derivative Instruments and Hedging Activities

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.

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, 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.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in “Gains (losses) on non-hedged interest rate derivatives” in the consolidated statements of operations. See Note 9 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 6). Our net income (loss) for partners’ capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the incentive distribution rights (“IDRs”) pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

3. ACQUISITIONS AND RELATED TRANSACTIONS:

Pending Acquisition

On July 19, 2011, ETE entered into a Second Amended and Restated Agreement and Plan of Merger (the “SUG Merger Agreement”) with Sigma Acquisition Corporation, a Delaware corporation and wholly-owned subsidiary of ETE (“Merger Sub”), and Southern Union Company, a Delaware corporation (“SUG”). The SUG Merger Agreement modifies certain terms of the Amended and Restated Agreement and Plan of Merger entered into by ETE, Merger Sub and SUG on July 4, 2011 (the “First Amended Merger Agreement”). Under the terms of the SUG Merger Agreement, Merger Sub will merge with and into SUG, with SUG continuing as the surviving entity and becoming a wholly-owned subsidiary of ETE (the “SUG Merger”), subject to certain conditions to closing.

Consummation of the SUG Merger is subject to customary conditions, including, without limitation: (i) the adoption of the Second Amended SUG Merger Agreement by the stockholders of SUG, (ii) the receipt of required approvals from the Federal Energy Regulatory Commission (the “FERC”), the Missouri Public Service Commission and, if required, the Massachusetts

Department of Public Utilities, (iii) the effectiveness of a registration statement on Form S-4 relating to the ETE Common Units to be issued in the SUG Merger, and (iv) the absence of any law, injunction, judgment or ruling prohibiting or restraining the SUG Merger or making the consummation of the SUG Merger illegal. On July 28, 2011, the waiting period applicable to the SUG Merger under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act") expired. On September 23, 2011, the FERC issued a letter order authorizing the transfer of FERC-jurisdictional facilities resulting from the SUG Merger. On October 27, 2011, the registration statement on Form S-4 was declared effective by the SEC. On December 9, 2011, the special meeting of the SUG stockholders was held and the SUG stockholders voted to approve the SUG Merger. ETE and SUG have made filings with the Missouri Public Service Commission and expect to receive its approval of the SUG Merger in the first quarter of 2012.

On July 19, 2011, we entered into an Amended and Restated Agreement and Plan of Merger with ETE (the "Amended Citrus Merger Agreement"). The Amended Citrus Merger Agreement modifies certain terms of the Agreement and Plan of Merger entered into by ETP and ETE on July 4, 2011. Pursuant to the terms of the Second Amended SUG Merger Agreement, immediately prior to the effective time of the SUG Merger, ETE will assign and SUG will assume the benefits and obligations of ETE under the Amended Citrus Merger Agreement. If we do not consummate the Citrus Acquisition on or before April 17, 2012, or the Citrus Merger Agreement is terminated at any time on or before such time, we must redeem the notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

Under the Amended Citrus Merger Agreement, it is anticipated that SUG will cause the contribution to ETP of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission pipeline system and is currently jointly owned by SUG and El Paso Corporation ("El Paso") (the "Citrus Acquisition"). The Citrus Acquisition will be effected through the merger of Citrus ETP Acquisition, L.L.C., a Delaware limited liability company and wholly-owned subsidiary of ETP, with and into CrossCountry Energy, LLC, a Delaware limited liability company and wholly-owned subsidiary of SUG that indirectly owns a 50% interest in Citrus Corp. ("CrossCountry"). In exchange for the interest in Citrus Corp., SUG will receive approximately $2.0 billion, consisting of approximately $1.9 billion in cash and $105 million of ETP common units, with the value of the ETP common units based on the volume-weighted average trading price for the ten consecutive trading days ending immediately prior to the date that is three trading days prior to the closing date of the Citrus Acquisition. In order to increase the expected accretion to be derived from the Citrus Acquisition, ETE has agreed to relinquish its rights to approximately $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters following the closing of the transaction.

The Amended Citrus Merger Agreement includes customary representations, warranties and covenants of ETP and ETE (including representations, warranties and covenants relating to SUG, CrossCountry and certain of CrossCountry's affiliates). Consummation of the Citrus Acquisition is subject to customary conditions, including, without limitation: (i) satisfaction or waiver of the closing conditions set forth in the SUG Merger Agreement, (ii) the receipt by ETP of any necessary waivers or amendments to its credit agreement, (iii) the amendment of our partnership agreement to reflect the agreed upon relinquishment by ETE of incentive distributions from ETP discussed above, and (iv) the absence of any order, decree, injunction or law prohibiting or making the consummation of the transactions contemplated by the Amended Citrus Merger Agreement illegal. The Amended Citrus Merger Agreement contains certain termination rights for both ETE and ETP, including among others, the right to terminate if the Citrus Acquisition is not completed by December 31, 2012 or if the SUG Merger Agreement is terminated.

Pursuant to the Amended Citrus Merger Agreement, ETE has granted ETP a right of first offer with respect to any disposition by ETE or SUG of Southern Union Gas Services, a subsidiary of SUG that owns and operates a natural gas gathering and processing system serving the Permian Basin in West Texas and New Mexico.

On November 17, 2011, CrossCountry filed a petition in the Court of Chancery in the State of Delaware seeking a declaratory judgment against El Paso that El Paso's right of first refusal under a Capital Stock Agreement ("CSA") governing the Citrus Corp. joint venture between CrossCountry and El Paso would not be triggered by the Citrus Acquisition. This petition was filed by CrossCountry following an exchange of letters between El Paso and SUG in which El Paso stated that it believed the Citrus Acquisition violated the provisions of the CSA related to transfers of equity interests with respect to Citrus Corp. On December 27, 2011, El Paso filed its answer to CrossCountry's petition and, in addition, El Paso brought third-party claims against ETP, ETE and SUG. El Paso’s third-party complaint against ETP seeks declaratory relief regarding El Paso’s rights under the CSA. Specifically, El Paso claims that the Citrus Acquisition violates its right of first refusal and seeks rescission of the Citrus Acquisition or, alternatively, damages. The parties are currently engaged in discovery and the case is scheduled to go to trial on April 26, 2012. ETP believes that El Paso’s assertions related to the Citrus Acquisition under the CSA are without merit.

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2012 Transaction

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas common units. AmeriGas assumed approximately $71 million of existing HOLP debt. In connection with the closing of this transaction, we entered into a support agreement with AmeriGas pursuant to which we are obligated to provide contingent, residual support of $1.5 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.5 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price. Under a unitholder agreement with AmeriGas, we are obligated to hold the approximately 29.6 million AmeriGas common units that we received in this transaction until January 2013.

We have not reflected our Propane operations as discontinued operations as we will have a continuing involvement in this business as a result of the investment in AmeriGas that was transferred as consideration for the transaction.

2011 Transactions

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC ("ETP-Regency LLC"), a joint venture owned 70% by the Partnership and 30% by Regency Energy Partners LP ("Regency"), acquired all of the membership interest in LDH Energy Asset Holdings LLC ("LDH"), from Louis Dreyfus Highbridge Energy LLC ("Louis Dreyfus") for approximately $1.98 billion in cash (the "LDH Acquisition"), including working capital adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas, and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH by Lone Star expands the Partnership's asset portfolio by adding an NGL platform with storage, transportation and fractionation capabilities.

We accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star's results of operations are included in our NGL transportation and services segment. Regency's 30% interest in Lone Star is reflected as noncontrolling interest.

The following table summarizes the assets acquired and liabilities assumed recognized as of the acquisition date:

Total current assets	$118,177
Property, plant and equipment(1)	1,419,591
Goodwill	432,026
Intangible assets	81,000
Other assets	157
	2,050,951
Total current liabilities	74,964
Other long-term liabilities	438
	75,402
Total consideration	1,975,549
Cash received	31,231
Total consideration, net of cash received	$1,944,318

(1) Property, plant and equipment (and estimated useful lives) consists of the following:

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Land and improvements	$30,759
Buildings and improvements (10 to 40 years)	3,123
Pipelines and equipment (20 to 65 years)	662,881
Natural gas liquids storage (40 years)	682,419
Linepack	704
Vehicles (3 to 20 years)	242
Furniture and fixtures (3 to 10 years)	49
Other (5 to 10 years)	8,526
Construction work-in-process	30,888
Property, plant and equipment	$1,419,591

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended 2011 and 2010 are presented as if the LDH Acquisition had been completed on January 1, 2010.

	Year Ended December 31,	
	2011	2010
Revenues	$6,959,029	$6,189,977
Net income	697,325	614,763
Net income attributable to partners	662,180	594,777
Basic net income (loss) per Limited Partner unit	$1.07	$1.08
Diluted net income (loss) per Limited Partner unit	$1.07	$1.07

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star for all periods presented;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting;
- include incremental interest expense related to the financing of ETP’s proportionate share of the purchase price; and
- reflect noncontrolling interest related to Regency’s 30% interest in Lone Star.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

2010 Transactions

In March 2010, we purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, we recorded customer contracts of $68.2 million and goodwill of $27.3 million.

2009 Transactions

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 August 2009, we acquired Energy Transfer Group, L.L.C. (“ETG”), as described in Note 11. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

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4. NET INCOME PER LIMITED PARTNER UNIT:

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,		
	2011	2010	2009
Net income attributable to partners	$668,974	$617,222	$791,542
General Partner’s interest in net income	433,148	387,729	365,362
Limited Partners’ interest in net income	235,826	229,493	426,180
Additional earnings allocated from General Partner	734	771	468
Distributions on employee unit awards, net of allocation to General Partner	(7,784)	(4,946)	(2,760)
Net income available to Limited Partners	$228,776	$225,318	$423,888
Weighted average Limited Partner units – basic	207,245,106	188,077,143	167,337,192
Basic net income per Limited Partner unit	$1.10	$1.20	$2.53
Weighted average Limited Partner units	207,245,106	188,077,143	167,337,192
Dilutive effect of unvested unit awards	909,197	640,253	431,789
Weighted average Limited Partner units, assuming dilutive effect of unvested unit awards	208,154,303	188,717,396	167,768,981
Diluted net income per Limited Partner unit	$1.10	$1.19	$2.53

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5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2011	2010
ETP Senior Notes:		
5.65% Senior Notes due August 1, 2012	$400,000	$400,000
6.0% Senior Notes due July 1, 2013	350,000	350,000
8.5% Senior Notes due April 15, 2014	350,000	350,000
5.95% Senior Notes due February 1, 2015	750,000	750,000
6.125% Senior Notes due February 15, 2017	400,000	400,000
6.7% Senior Notes due July 1, 2018	600,000	600,000
9.7% Senior Notes due March 15, 2019	600,000	600,000
9.0% Senior Notes due April 15, 2019	650,000	650,000
4.65% Senior Notes due June 1, 2021	800,000	—
6.625% Senior Notes due October 15, 2036	400,000	400,000
7.5% Senior Notes due July 1, 2038	550,000	550,000
6.05% Senior Notes due June 1, 2041	700,000	—
Transwestern Senior Notes:		
5.39% Senior Notes due November 17, 2014	88,000	88,000
5.54% Senior Notes due November 17, 2016	125,000	125,000
5.64% Senior Notes due May 24, 2017	82,000	82,000
5.36% Senior Notes due December 9, 2020	175,000	175,000
5.89% Senior Notes due May 24, 2022	150,000	150,000
5.66% Senior Notes due December 9, 2024	175,000	175,000
6.16% Senior Notes due May 24, 2037	75,000	75,000
HOLP Senior Secured Notes:		
Senior Secured Notes with interest rates ranging from 7.26% to 8.87%	71,314	103,127
ETP Revolving Credit Facility	314,438	402,327
Other long-term debt	10,345	9,541
Unamortized discounts	(15,457)	(12,074)
Fair value adjustments related to interest rate swaps	11,647	17,260
	7,812,287	6,440,181
Current maturities	(424,117)	(35,265)
	$7,388,170	$6,404,916

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The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude (i) maturities of long-term debt related to our Propane Business, which was contributed to AmeriGas in January 2012 (see Note 3), and (ii) $3.8 million in unamortized discounts and fair value adjustments related to interest rate swaps:

2012	$400,000
2013	350,000
2014	438,000
2015	750,000
2016	439,438
Thereafter	5,357,000
Total	$7,734,438

Long-term debt reflected on our consolidated balance sheet includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap. As of December 31, 2011 long-term debt includes $11.6 million of fair value adjustments to interest rate swaps, which will be amortized as a reduction of interest expense until 2015.

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

The 9.7% ETP Senior Notes contain a put option on March 15, 2012. The current market value of these notes is significantly in excess of the principal amount making a repurchase at par value uneconomic by the holder. However, if such repurchase were to occur, we would refinance any amounts paid on a long-term basis.

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 May 2011, we completed a public offering of $800 million aggregate principal amount of 4.65% Senior Notes due June 1, 2021 and $700 million aggregate principal amount of 6.05% Senior Notes due June 1, 2041. We used the net proceeds of $1.48 billion to repay all of the borrowings outstanding under our revolving credit facility, to fund capital expenditures related to pipeline construction projects and for general partnership purposes. We may redeem some or all of the notes at any time and from time to time pursuant to the terms of the indenture subject to the payment of a "make-whole" premium. Interest will be paid semi-annually.

In January 2012, we completed a public offering of $1 billion aggregate principal amount of 5.20% Senior Notes due February 1, 2022 and $1 billion aggregate principal amount of 6.50% Senior Notes due February 1, 2042. We will use the net proceeds of $1.98 billion to fund the cash portion of the purchase price of the Citrus Acquisition and for general partnership purposes. We may redeem some or all of the notes at any time and from time to time pursuant to the terms of the indenture subject to the payment of a "make-whole" premium. Interest will be paid semi-annually. If we do not consummate the Citrus Acquisition on or before April 17, 2012, or the Citrus Merger Agreement is terminated on or before such date, we must redeem the $2.0 billion of senior notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest.

In January 2012, we announced a cash tender offer for up to $750 million aggregate principal amount of specified series of the ETP Senior Notes. The tender offer consisted of two separate offers: an Any and All Offer and a Maximum Tender Offer.

In the Any and All Offer, we offered to purchase, under certain conditions, any and all of our 5.65% Senior Notes due August 1, 2012, at a fixed price. Pursuant to the Any and All Offer, we purchased $292.0 million in aggregate principal amount on January 19, 2012.

In the Maximum Tender Offer, we offered to purchase, under certain conditions, certain series of outstanding ETP Senior Notes at a fixed spread over the index rate. Pursuant to this tender offer, on February 7, 2012, we purchased $200.0 million aggregate principal amount of our 9.7% Senior Notes due March 15, 2019, $200.0 million aggregate principal amount of our

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9.0% Senior Notes due April 15, 2019 and $58.1 million aggregate principal amount of our 8.5% Senior Notes due April 15, 2014.

Transwestern Senior Notes

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. The balance is payable upon maturity. Interest is paid semi-annually.

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 Notes. Interest is paid quarterly or semiannually and principal payments are made in annual installments through 2020 except for a one time payment of $16.0 million due in 2013. Subsequent to our contribution of the Propane Business, this debt was assumed by AmeriGas.

Revolving Credit Facility

The indebtedness under ETP's revolving credit facility (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.

As of December 31, 2011, we had $314.4 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $2.16 billion taking into account letters of credit of $25.6 million. The weighted average interest rate on the total amount outstanding as of December 31, 2011 was 1.78%.

On October 27, 2011, we amended and restated the ETP Credit Facility to, among other things, (i) allow for borrowings of up to $2.5 billion; (ii) extend the maturity date from July 20, 2012 to October 27, 2016 (which may be extended by one year with lender approval); (iii) allow for an increase in the size of the credit facility to $3.75 billion (subject to obtaining lender commitments for the additional borrowing capacity); and (iv) to adjust the interest rates and commitment fees to current market terms. Following this amendment and based on our current ratings, the interest margin for LIBOR rate loans is 1.50% and the commitment fee for unused borrowing capacity is 0.25%.

Covenants Related to Our Credit Agreements

The agreements relating 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 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; and
- enter into restrictive agreements.

The credit agreement relating to the ETP Credit Facility also contains a financial covenant that provides that the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1 as of the end of each quarter, with a permitted increase to 5.5 to 1 during a Specified Acquisition Period, as defined in the ETP Credit Facility.

The agreements relating to the Transwestern senior notes 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

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ratio.
Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities 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 were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2011.

6. EQUITY:

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, 2011, there were issued and outstanding 225,468,108 Common Units representing an aggregate 98.5% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.
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 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 (as defined in our Partnership Agreement) 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 was as follows:

	Years Ended December 31,		
	2011	2010	2009
Number of Common Units, beginning of period	193,212,590	179,274,747	152,102,471
Common Units issued in connection with public offerings	29,440,000	20,700,000	23,575,000
Common Units issued in connection with certain acquisitions	66,499	—	1,450,076
Common Units issued in connection with the Distribution Reinvestment Plan	353,679	—	—
Common Units issued in connection with the equity distribution program	1,951,715	5,194,287	1,891,691
Issuance of Common Units under equity incentive plans	443,625	317,386	255,509
Redemption of Common Units in connection with MEP Transaction (See Note 11)	—	(12,273,830)	—
Number of Common Units, end of period	225,468,108	193,212,590	179,274,747

Our Common Units are registered under the Securities Exchange Act of 1934 (as amended) 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
January 2009	6,900,000	$34.05	$225,354	(2)
April 2009	9,775,000	37.55	352,369	(3)
October 2009	6,900,000	41.27	275,979	(2)
January 2010	9,775,000	44.72	423,551	(2)(3)
August 2010	10,925,000	46.22	489,418	(2)(3)
April 2011	14,202,500	50.52	695,496	(3)
November 2011	15,237,500	44.67	660,241	(2)(3)

(1)Number of Common Units includes the exercise of the overallotment options by the underwriters.
(2)Proceeds were used to repay amounts outstanding under the ETP Credit Facility.
(3)Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

Equity Distribution Program

In December 2010, we entered into an Equity Distribution Agreement with Credit Suisse Securities (USA) LLC (“Credit Suisse”). According to the provisions of this agreement, we may offer and sell from time to time through Credit Suisse, as our sales agent, Common Units having an aggregate offering price of up to $200.0 million. Sales of the units are made by means of ordinary brokers’ transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and Credit Suisse. Under the terms of this agreement, we may also sell Common Units to Credit Suisse as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to Credit Suisse as principal would be pursuant to the terms of a separate agreement between us and Credit Suisse.
During 2011, we received proceeds from units issued pursuant to this agreement of approximately $96.3 million, net of commissions, which proceeds were used for general partnership purposes. Approximately $69.6 million of our Common Units remain available to be issued under the agreement based on trades initiated through December 31, 2011.

Previously, we had an Equity Distribution Agreement with UBS Securities LLC ("UBS"), which was similar to our existing agreement with Credit Suisse as described above. During 2010, we received proceeds from units issued pursuant to this agreement of approximately $214.3 million, net of commissions, which proceeds were used to repay amounts outstanding under our revolving credit facility.

Equity Incentive Plan Activity

As discussed in Note 7, 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.

Distribution Reinvestment Program

In April 2011, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the “DRIP”). The DRIP provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. The registration statement covers the issuance of up to 5,750,000 Common Units under the DRIP.

During 2011, distributions of approximately $15.0 million were reinvested under the DRIP resulting in the issuance of 353,679 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, with any excess thereof available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests. The Class E Units are treated as treasury units for accounting purposes
because they are owned by our wholly-owned subsidiary, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the Class E Units at a future date.

Quarterly Distributions of Available Cash

The Partnership Agreement requires that we distribute all of our Available Cash to our Unitholders and our General Partner within forty-five 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 of Available Cash from operating surplus, excluding incentive distributions, to our General Partner and Limited Partner interests are based on their respective interests as of the distribution record date. Incentive distributions allocated to our General Partner are determined based on the amount by which quarterly distribution to common Unitholders exceed certain specified target levels, as set forth in our Partnership Agreement.

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

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2011	November 4, 2011	November 14, 2011	$0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
December 31, 2010	February 7, 2011	February 14, 2011	0.89375
September 30, 2010	November 8, 2010	November 15, 2010	$0.89375
June 30, 2010	August 9, 2010	August 16, 2010	0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375
December 31, 2009	February 8, 2010	February 15, 2010	0.89375
September 30, 2009	November 9, 2009	November 16, 2009	$0.89375
June 30, 2009	August 7, 2009	August 14, 2009	0.89375
March 31, 2009	May 8, 2009	May 15, 2009	0.89375
December 31, 2008	February 6, 2009	February 13, 2009	0.89375

On January 25, 2012, we declared a cash distribution for the three months ended December 31, 2011 of $0.89375 per Common Unit. We paid this distribution on February 14, 2012 to Unitholders of record at the close of business on February 7, 2012.

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The total amounts of distributions declared during the years ended December 31, 2011, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Years Ended December 31,		
	2011	2010	2009
Limited Partners:			
Common Units	$762,350	$676,798	$629,263
Class E Units	12,484	12,484	12,484
General Partner interest	19,603	19,524	19,505
Incentive Distribution Rights	421,888	375,979	350,486
	$1,216,325	$1,084,785	$1,011,738

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31,	
	2011	2010
Net gains on commodity related hedges	$6,455	$25,245
Unrealized gains on available-for-sale securities	114	918
Total AOCI, net of tax	$6,569	$26,163

7. UNIT-BASED COMPENSATION PLANS:

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2011, an aggregate total of 2,788,181 ETP Common Units remain available to be awarded under our equity incentive plans.

Unit Grants

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year period at 20% per year, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. 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."

Under our equity incentive plans, our non-employee directors each receive grants that vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

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, 2010	1,936,578	$43.95
Awards granted	1,386,251	48.35
Awards vested	(610,557)	44.07
Awards forfeited	(148,563)	42.74
Unvested awards as of December 31, 2011	2,563,709	46.37

During the years ended December 31, 2011, 2010 and 2009, the weighted average grant-date fair value per unit award granted

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was $48.35, $49.82 and $43.56, respectively. The total fair value of awards vested was $26.9 million, $16.5 million and $14.7 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2011, a total of 2,563,709 unit awards remain unvested, for which ETP expects to recognize a total of $79.4 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 indirectly owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. 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.

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, 2011, 2010 and 2009, we recognized non-cash compensation expense, net of forfeitures, of $2.0 million, $3.7 million and $6.4 million, respectively, as a result of these awards. As of December 31, 2011, rights related to 180,000 ETE common units remain outstanding, for which we expect to recognize a total of $1.0 million in compensation expense over a weighted average period of 1.0 years.

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

Regulatory Matters

On September 21, 2011, in lieu of filing a new general rate case filing under Section 4 of the NGA, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. Transwestern is required to file a new general rate case on October 1, 2014. However, shippers which were not parties to the settlement have the right to challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint.

Guarantee - Fayetteville Express Pipeline LLC

Fayetteville Express Pipeline LLC (“FEP”), a joint venture entity in which we own a 50% interest, had a credit agreement that provided for a $1.1 billion senior revolving credit facility (the “FEP Facility”). We guaranteed 50% of the obligations of FEP under the FEP Facility, with the remainder of FEP Facility obligations guaranteed by Kinder Morgan Energy Partners, L.P. (“KMP”). Amounts borrowed under the FEP Facility bore interest at a rate based on either a Eurodollar rate or a prime rate.

In July 2011, the FEP Facility was repaid with capital contributions from ETP and KMP totaling $390 million along with proceeds from a $600 million term loan credit facility maturing in July 2012 (which can be extended for one year at the option of FEP). Upon closing and funding of the term loan facility, the FEP Facility was terminated. FEP also entered into a $50 million revolving credit facility maturing in July 2015. FEP’s indebtedness under its new credit facilities is not guaranteed by ETP or KMP.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Transaction described in Note 3, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550 million in aggregate principal amount of 6.75% senior notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% senior notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the Propane Transaction, ETP entered into and delivered a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt as defined in the CRSA.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas. We believe that these pipelines do not provide interstate service and that they are thus not subject to the jurisdiction of the FERC under the Interstate Commerce Act (“ICA”) and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. We cannot guarantee that the jurisdictional status of our NGL facilities will remain unchanged; however, should they be found

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jurisdictional, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have 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 2029. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $26.1 million, $21.1 million and $19.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Future minimum lease commitments for such leases are:

Years Ending December 31:	
2012	$19,795
2013	18,874
2014	16,304
2015	16,220
2016	16,327
Thereafter	149,844

Amounts reflected above do not include future minimum lease commitments for our propane operations, which was deconsolidated in January 2012 in connection with the contribution of these operations described in Note 3.

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

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.

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 and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2011 and 2010, accruals of approximately $18.2 million and $10.2 million, respectively, were reflected on our balance sheets related to these contingent obligations. 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 there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

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No amounts have been recorded in our December 31, 2011 or 2010 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as 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 business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. 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. Moreover, there can be no assurance 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, will not result in substantial costs and liabilities. We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

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, 2011 and 2010, accruals on an undiscounted basis of $13.7 million and $13.8 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities related to environmental matters.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”). 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 2025 is $5.7 million, which is included in the aggregate environmental accruals discussed above. Transwestern received approval from the FERC for the continuation of rate recovery of projected soil and groundwater remediation costs not related to PCBs for the term of its rate case settlement.

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 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 U.S. Environmental Protection Agency’s (the “EPA”) Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. 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.

Petroleum-based contamination or other 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, and we believe that our operations have not contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2011 or 2010 consolidated balance sheets. Based on information currently available to us, the presence of contamination and remediation activities at these sites are not expected to have a material adverse effect on our financial condition or results of operations.

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On August 20, 2010, the EPA published new regulations under the federal Clean Air Act ("CAA") to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule is required by October 2013.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule's requirements, because the rule applies only to changes we might make in the future.

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, 2011, 2010 and 2009, $18.3 million, $13.3 million and $31.4 million, respectively, of capital costs and $14.7 million, $15.4 million and $18.5 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 ETP to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act ("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.

9. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To 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, swaps and options and are recorded at fair value in the consolidated balance sheets.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., 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 into 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

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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 mark-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 through either mark-to-market adjustments or the physical withdrawal of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting, are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

During the fourth quarter of 2011, our trading activities included the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment's operations and are accounted for in cost of products sold in our consolidated statements of operations. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our midstream segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against 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. To the extent that financial contracts are not tied to physical delivery volumes, we may engage in offsetting 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.

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

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The following table details our outstanding commodity-related derivatives:

	December 31, 2011		December 31, 2010	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu) - trading (1)	(151,260,000)	2012-2013	—	—
Basis Swaps IFERC/NYMEX (MMBtu) - non-trading	(61,420,000)	2012-2013	(38,897,500)	2011
Swing Swaps IFERC (MMBtu)	92,370,000	2012-2013	(19,720,000)	2011
Fixed Swaps/Futures (MMBtu)	797,500	2012	(2,570,000)	2011
Forward Physical Contracts (MMBtu)	(10,672,028)	2012	—	—
Options — Calls (MMBtu)	—	—	(3,000,000)	2011
Propane:				
Forwards/Swaps (Gallons)	38,766,000	2012-2013	1,974,000	2011
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(28,752,500)	2012	(28,050,000)	2011
Fixed Swaps/Futures (MMBtu)	(45,822,500)	2012	(39,105,000)	2011
Hedged Item — Inventory (MMBtu)	45,822,500	2012	39,105,000	2011
Cash Flow Hedging Derivatives				
Natural Gas:				
Fixed Swaps/Futures (MMBtu)	—	—	(210,000)	2011
Options – Puts (MMBtu)	3,600,000	2012	26,760,000	2011-2012
Options – Calls (MMBtu)	(3,600,000)	2012	(26,760,000)	2011-2012
Propane:				
Forwards/Swaps (Gallons)	—	—	32,466,000	2011

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

We expect gains of $6.4 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage our current interest rate exposures by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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We had the following interest rate swaps outstanding as of December 31, 2011 and 2010, none of which are designated as hedges for accounting purposes:

Term	Type [1]	Notional Amount Outstanding December 31, 2011	December 31, 2010
May 2012[2]	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	$350,000	$—
August 2012[2]	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	500,000	400,000
July 2013[2]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	300,000	—
July 2018	Pay a floating rate plus a spread of 4.01% and receive a fixed rate of 6.70%	500,000	500,000

(1) As of December 31, 2011, floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

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 or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream and power generation 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. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

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, and 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 $66.2 million and $52.2 million as of December 31, 2011 and 2010, respectively.

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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Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2011 and 2010:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	2011	2010	2011	2010
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$77,197	$35,031	$(819)	$(6,631)
Commodity derivatives	—	6,589	—	—
	77,197	41,620	(819)	(6,631)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	227,337	64,940	(251,268)	(72,729)
Commodity derivatives	708	275	(4,844)	—
Interest rate derivatives	36,301	20,790	(117,020)	(18,338)
	264,346	86,005	(373,132)	(91,067)
Total derivatives	$341,543	$127,625	$(373,951)	$(97,698)

The commodity derivatives (margin deposits) are recorded in "Other current assets" on our consolidated balance sheets. The remainder of the derivatives are recorded in "Price risk management assets/liabilities."

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.

The following tables summarize the amounts recognized with respect to our derivative financial instruments for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)		
	Years Ended December 31,		
	2011	2010	2009
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$19,047	$60,764	$3,143
Interest rate derivatives	—	(1,366)	—
Total	$19,047	$59,398	$3,143

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	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
		Years Ended December 31,		
		2011	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$37,703	$37,325	$9,924
Interest rate derivatives	Interest expense	—	(1,493)	287
Total		$37,703	$35,832	$10,211

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion		
		Years Ended December 31,		
		2011	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$283	$18	$—
Total		$283	$18	$—

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness		
		Years Ended December 31,		
		2011	2010	2009
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$34,000	$16,210	$60,045
Total		$34,000	$16,210	$60,045

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2011	2010	2009
Derivatives not designated as hedging instruments:				
Commodity derivatives - Trading	Cost of products sold	$(29,777)	$—	$—
Commodity derivatives - Non-trading	Cost of products sold	$9,257	$11,584	$99,807
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	(77,409)	4,616	39,239
Total		$(97,929)	$16,200	$139,046

We recognized unrealized losses of $20.8 million, $47.4 million, and $18.6 million of unrealized losses 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, 2011, 2010 and 2009, respectively. In addition, for the years ended December 31, 2011, 2010 and 2009, we recognized unrealized gains of $9.5 million, $17.4 million and $48.6 million, respectively, on commodity derivatives and related hedged inventory accounted for as fair value hedges.

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10. 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. We made matching contributions of $11.3 million, $9.8 million and $9.8 million to the 401(k) savings plan for the years ended December 31, 2011, 2010 and 2009, respectively.

11. RELATED PARTY TRANSACTIONS:
We previously held a 50% interest in Midcontinent Express Pipeline LLC ("MEP"), a joint venture with Kinder Morgan Energy Partners, L.P. (KMP). On May 26, 2010 we transferred a majority of our interest in MEP to ETE in exchange for 12,273,830 common units previously held by ETE. In conjunction with this transfer, we recorded a non-cash charge of approximately $52.6 million during 2010 to reduce the carrying value of our investment in MEP to its estimated fair value. As a part of this transaction, ETE transferred its interest in MEP to Regency in exchange for Regency Common Units. Along with this transaction ETE also transferred its option to purchase ETP's remaining 0.1% interest in MEP. On September 1, 2011, Regency exercised its option to acquire our remaining 0.1% interest in MEP for approximately $1.2 million in cash.
Regency became a related party on May 26, 2010 when ETE acquired all of the equity interest in the general partner of Regency. We provide Regency with certain natural gas sales and transportation services and compression equipment and Regency provides us with certain contract compression services. For the year ended December 31, 2011, we recorded revenue of $34.1 million, costs of products sold of $34.3 million and operating expenses of $2.5 million related to transactions with Regency. For the period from May 26, 2010 to December 31, 2010, we recorded revenue of $4.0 million, costs of products sold of $4.0 million and operating expenses of $0.5 million related to transactions with Regency.
We received $17.1 million, $6.3 million and $0.5 million in management fees from ETE for the provision of various general and administrative services for ETE's benefit for the years ended December 31, 2011, 2010 and 2009, respectively. The increase recorded in the years ended December 31, 2011 and 2010 were the result of increased service fees related to the provision of various general and administrative services for Regency which was acquired by ETE in 2010. In addition, the management fees for the year ended December 31, 2011 include the provision of various general and administrative services for Regency. For the year ended December 31, 2011 we recorded from Regency $6.6 million for reimbursement of various general and administrative expenses incurred by us.
For the year ended December 31, 2011 revenue of $1.9 million and cost of products sold of $1.2 million are included in our consolidated statement of operations related to transactions with FEP, our unconsolidated affiliate. For the year ended December 31, 2010 revenue of $26.0 million and cost of products sold of $20.5 million are included in our consolidated statement of operations related to transactions with FEP, our unconsolidated affiliate.
Enterprise Products Partners L.P. ("Enterprise") is considered to be a related party to us due to Enterprise's holdings of outstanding common units of ETE. We and Enterprise transport natural gas on each other's pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that expires in 2015 and includes an option to extend the agreement for an additional year.
The following table presents sales to and purchases from Enterprise:

	Years Ended December 31,		
	2011	2010	2009
Natural Gas Operations:			
Sales	$654,129	$538,657	$414,333
Purchases	26,992	23,592	48,528
Propane Operations:			
Sales	10,613	15,527	19,961
Purchases	471,046	415,897	343,540

As of December 31, 2011 and 2010, Titan had forward mark-to-market derivatives for approximately 38.8 million and 1.7 million gallons of propane at a fair value liability of $4.1 million and a fair value asset of $0.2 million, respectively, with Enterprise. In addition, as of December 31, 2010, Titan had forward derivatives accounted for as cash flow hedges of 32.5 million gallons of propane at a fair value asset of $6.6 million with Enterprise. Our propane operations discontinued cash

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flow hedge accounting in July 2011; therefore, all of their forward derivatives are currently accounted for using mark-to-market accounting.

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

	As of December 31,	
	2011	2010
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$54,644	$36,736
Propane Operations	—	2,327
Other	27,109	14,803
Total accounts receivable from related parties:	$81,753	$53,866
Accounts payable from related parties:		
Enterprise:		
Natural Gas Operations	$2,198	$2,687
Propane Operations	27,770	22,985
Other	3,405	1,505
Total accounts payable from related parties:	$33,373	$27,177
Net imbalance receivable from (payable to) Enterprise	$(780)	$1,360

On January 18, 2012, Enterprise sold a significant portion of its ownership in ETE's common units. Subsequent to that transaction Enterprise owns less than 5% of ETE's outstanding common units.

Effective August 17, 2009, we acquired 100% of the membership interests of 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 our Chief Executive Officer 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. We have not accrued any contingent payments related to this agreement.

Subsequent to the acquisition of ETG, we pay $4.7 million in operating lease payments per year to the former owners for the use of compressor equipment through 2017.

12. REPORTABLE SEGMENTS:

Our financial statements reflect five reportable segments, which conduct their business exclusively in the United States of America, as follows:

- intrastate natural gas transportation and storage;
- interstate natural gas transportation;
- midstream;
- NGL transportation and services (See Note 3); and
- retail propane and other retail propane related operations.

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales

and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our retail propane and other retail propane related segment are primarily reflected in retail propane sales and other.

We previously reported segment operating income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

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

	Years Ended December 31,		
	2011	2010	2009
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$2,397,887	$2,075,217	$1,773,528
Intersegment revenues	276,270	1,215,688	618,016
	2,674,157	3,290,905	2,391,544
Interstate transportation – revenues from external customers	446,743	292,419	270,213
Midstream:			
Revenues from external customers	2,041,600	1,955,627	2,060,451
Intersegment revenues	551,783	1,213,687	380,709
	2,593,383	3,169,314	2,441,160
NGL transportation and services:			
Revenues from external customers	362,701	—	—
Intersegment revenues	34,400	—	—
	397,101	—	—
Retail propane and other retail propane related – revenues from external customers	1,468,082	1,419,646	1,292,583
All other:			
Revenues from external customers	133,427	141,918	20,520
Intersegment revenues	54,155	145,405	1,145
	187,582	287,323	21,665
Eliminations	(916,608)	(2,574,780)	(999,870)
Total revenues	$6,850,440	$5,884,827	$5,417,295
Cost of products sold:			
Intrastate transportation and storage	$1,774,006	$2,381,397	$1,393,295
Midstream	2,085,951	2,759,113	2,116,279
NGL transportation and services	218,283	—	—
Retail propane and other retail propane related	860,323	774,742	596,002
All other	155,374	235,614	16,350
Eliminations	(904,584)	(2,550,925)	(999,870)
Total cost of products sold	$4,189,353	$3,599,941	$3,122,056
Depreciation and amortization:			
Intrastate transportation and storage	$119,600	$116,992	$107,605
Interstate transportation	80,839	52,582	48,297
Midstream	111,226	85,942	70,845
NGL transportation and services	32,459	—	—
Retail propane and other retail propane related	82,310	81,947	83,476
All other	4,470	5,548	2,580
Total depreciation and amortization	$430,904	$343,011	$312,803

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	Years Ended December 31,		
	2011	2010	2009
Segment Adjusted EBITDA			
Intrastate transportation and storage	$667,294	$716,176	$768,934
Interstate transportation	373,409	220,027	228,705
Midstream	388,578	329,025	206,232
NGL transportation and services	88,197	—	—
Retail propane and other retail propane related	222,204	269,670	270,027
All other	2,881	5,990	3,492
Total Segment Adjusted EBITDA	1,742,563	1,540,888	1,477,390
Depreciation and amortization	(430,904)	(343,011)	(312,803)
Interest expense, net of interest capitalized	(474,113)	(412,553)	(394,274)
Gains (losses) on non-hedged interest rate derivatives	(77,409)	4,616	39,239
Income tax expense	(18,815)	(15,536)	(12,777)
Non-cash compensation expense	(37,457)	(27,180)	(24,032)
Allowance for equity funds used during construction	957	28,942	10,557
Unrealized gains (losses) on commodity risk management activities	(11,407)	(78,300)	29,980
Impairment of investments in affiliates	(5,355)	(52,620)	—
Losses on disposal of assets	(3,188)	(5,043)	(1,564)
Adjusted EBITDA attributable to noncontrolling interest	37,842	—	—
Proportionate share of unconsolidated affiliates' interest, depreciation and allowance for equity funds used during construction	(29,994)	(22,499)	(22,331)
Other, net	4,442	(482)	2,157
Net income	697,162	617,222	791,542
Less: Net income attributable to noncontrolling interest	28,188	—	—
Net income attributable to partners	$668,974	$617,222	$791,542

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	As of December 31,		
	2011	2010	2009
Total assets:			
Intrastate transportation and storage	$4,784,630	$4,894,352	$4,901,102
Interstate transportation	3,661,098	3,390,588	3,313,837
Midstream	2,665,610	1,842,370	1,523,538
NGL transportation and services	2,360,095	—	—
Retail propane and other retail propane related	1,783,770	1,791,254	1,784,353
All other	263,413	231,428	212,142
Total	$15,518,616	$12,149,992	$11,734,972

	Years Ended December 31,		
	2011	2010	2009
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate transportation and storage	$52,388	$117,295	$378,494
Interstate transportation	207,962	872,112	99,341
Midstream	836,841	404,669	95,081
NGL transportation and services	1,745,035	—	—
Retail propane and other retail propane related	66,053	64,520	62,953
All other	13,586	11,405	44,911
Total	$2,921,865	$1,470,001	$680,780

13. 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 March 31	June 30	September 30	December 31	Total Year
2011:					
Revenues	$1,687,577	$1,628,095	$1,715,316	$1,819,452	$6,850,440
Gross profit	693,120	619,467	639,790	708,710	2,661,087
Operating income	363,135	270,419	272,343	338,910	1,244,807
Net income	247,202	156,616	76,050	217,294	697,162
Limited Partners’ interest in net income (loss)	139,663	42,336	(38,045)	91,872	235,826
Basic net income per limited partner unit (loss)	$0.71	$0.19	$(0.19)	$0.41	$1.10
Diluted net income per limited partner unit (loss)	$0.71	$0.19	$(0.19)	$0.41	$1.10
2010:					
Revenues	$1,871,981	$1,267,706	$1,290,644	$1,454,496	$5,884,827
Gross profit	647,116	496,849	513,233	627,688	2,284,886
Operating income	344,338	199,184	208,147	306,502	1,058,171
Net income	240,111	42,843	107,387	226,881	617,222
Limited Partners’ interest in net income (loss)	140,112	(47,756)	10,341	126,796	229,493
Basic net income per limited partner unit (loss)	$0.74	$(0.26)	$0.05	$0.65	$1.20
Diluted net income per limited partner unit (loss)	$0.74	$(0.26)	$0.05	$0.65	$1.19

For the three months ended September 30, 2011 and June 30, 2010, distributions paid for the period exceeded net income attributable to partners by $229.2 million and $213.3 million, respectively. 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.