Energy Transfer Partners, L.P.
Form 10-K
February 27, 2014
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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, 2013
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 28, 2013, 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 $13.80 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 21, 2014, the registrant had 316,923,087 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (the “Partnership,” or “ETP”) 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,” “estimate,” “goal,” “ “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 or expected, 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
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
AROs	asset retirement obligations
Bbls	barrels
Bcf	billion cubic feet
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 used
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
Citrus	Citrus Corp.
CrossCountry	CrossCountry Energy, LLC
DOT	U.S. Department of Transportation
Eastern Gulf	Eastern Gulf Crude Access, LLC, a joint venture owned 60% by ETE and 40% by ETP
ETC Compression	ETC Compression, LLC

ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP Credit Facility	ETP’s $2.5 billion revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP

ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Holdco	ETP Holdco Corporation
HOLP	Heritage Operating, L.P.
IDRs	incentive distribution rights
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas
MACS	Mid-Atlantic Convenience Stores
MGE	Missouri Gas Energy
MMBtu	million British thermal units
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NEG	New England Gas Company
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter

Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC, a wholly-owned subsidiary of Southern Union, which owns the general partner and 100% of the limited partner interests in PEPL
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of PEPL
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas)

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SUGS	Southern Union Gas Services
Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
TRRC	Texas Railroad Commission
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC
Trunkline LNG	Trunkline LNG Company, LLC, a subsidiary of PEPL

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, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include 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 based on 100% of the subsidiaries’ results of operations and for unconsolidated affiliates based on the Partnership’s proportionate ownership.

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PART I

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 $18.59 billion as of January 31, 2014). 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 primary activities in which we are engaged, all of which are in the United States, and the 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 we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Refined product and crude oil operations, including the following:
  - refined product and crude oil transportation through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco and MACS.

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The following chart summarizes our organizational structure as of December 31, 2013. For simplicity, certain immaterial entities and ownership interest have not been depicted.

(1) On January 10, 2014, as part of our effort to simplify our structure, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle as the surviving entity.

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.”

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Significant Achievements in 2013 and Beyond

Strategic Transactions

Our significant strategic transactions in 2013 and beyond included the following, as discussed in more detail herein:

- On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP.
- On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, which owns the general partner and IDRs of ETP, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.
- On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates.
- On July 12, 2013, the Partnership received $346 million in net proceeds from the sale of 7.5 million of its AmeriGas common units, which were received in connection with the Partnership's contribution of its retail propane operations to AmeriGas in January 2012. In January 2014, we sold 9.2 million AmeriGas common units for net proceeds of $381 million.
- In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.
- In October 2013, La Grange Acquisition, L.P., an indirect wholly-owned subsidiary of ETP, acquired convenience store operator MACS with a network of approximately 300 company-owned and dealer locations. These operations were reflected in ETP's retail marketing segment, along with the retail marketing operations owned by Sunoco, beginning in the fourth quarter of 2013.
- On October 31, 2013, ETP and ETE exchanged 50.2 million ETP Common Units, owned by ETE, for newly issued Class H Units by ETP that track 50% of the underlying economics of the general partner interest and the IDRs of Sunoco Logistics.
- On January 10, 2014, as part of our effort to simplify our structure, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle as the surviving entity.
- In January, ETP's Board of Directors approved a second consecutive increase in its quarterly distribution to $0.92 per unit ($3.68 annualized) on ETP Common Units for the quarter ended December 31, 2013, representing an increase of $0.06 per Common Unit on an annualized basis compared to the quarter ended September 30, 2013 and an increase of $0.105 per Common Unit on an annualized basis compared to the quarter ended December 31, 2012.
- On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014.

Significant Organic Growth Projects

Our significant organic growth projects in 2013 included the following, as discussed in more detail herein:

- On August 7, 2013, Lake Charles Exports, LLC, an entity owned by BG LNG Services, LLC and Trunkline LNG Holdings, LLC, received an order from the Department of Energy conditionally granting authorization to export up to 15 million metric tonnes per annum of LNG to non-free trade agreement countries from the existing LNG import terminal owned by Trunkline LNG Company, LLC, which is located in Lake Charles, Louisiana. Lake Charles Exports, LLC previously received approval to export LNG from the Lake Charles facility to free trade agreement countries on July 22, 2011. In October 2013, Trunkline

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and BG Group announced their entry into a project development agreement to jointly develop the LNG export project at the existing Trunkline LNG import terminal.

- During 2013, the following significant growth projects were placed in service:
- In November 2013, we announced that Lone Star has placed in service a second 100,000 barrel-per-day NGL fractionator at its facility in Mont Belvieu, Texas, bringing Lone Star's total fractionation capacity at Mont Belvieu to 200,000 Bbls/d.
- An aggregate of 1.0 Bcf/d of natural gas processing capacity brought online, which includes the most recent phase of the Jackson County plant, bringing the total processing capacity at Jackson to 800 MMcf/d as well as an incremental 200 MMcf/d cryogenic processing plant at the Godley processing facility.
- Growth projects placed into service during 2013 totaled $1.20 billion and we have announced growth projects aggregating $830 million that are expected to be placed in service through 2014.
- We are currently developing plans to convert existing pipeline assets from natural gas transportation to crude oil transportation. These plans include the proposed abandonment of certain pipeline segments of Trunkline, which are currently operating in natural gas service, and the conversion of some or all of those segments of pipeline to crude oil transportation service. Trunkline's application to abandon those segments of pipeline from natural gas service has been approved by the FERC. Subject to receipt of sufficient customer commitments for long-term transportation capacity and regulatory approvals, this project is expected to be in service by 2016.

Segment Overview

During the fourth quarter 2013, management realigned the composition of our reportable segments, and as a result, our natural gas marketing operations are now aggregated into the "all other" segment. These operations were previously reported in the midstream segment. See Note 14 to our consolidated financial statements for additional financial information about our segments.

Intrastate Transportation and Storage Segment

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. Through our intrastate transportation and storage segment, we own and operate approximately 7,800 miles of natural gas transportation pipelines with approximately 14.0 Bcf/d of transportation capacity 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.

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 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 EDF Inc., Motiva Enterprises LLC, XTO Energy, Inc. ("XTO"), Chesapeake Energy Marketing, Inc., and Natural Gas Exchange, Inc.

Interstate Transportation and Storage Segment

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. Through our interstate transportation and storage

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segment, we directly own and operate approximately 12,800 miles of interstate natural gas pipeline with approximately 11.3 Bcf/d of transportation capacity and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline. ETP also owns a 50% interest in Citrus which owns 100% of FGT, an approximately 5,400 mile pipeline system that extends from south Texas through the Gulf Coast to south Florida.

Our interstate transportation and storage segment includes Panhandle, which owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the PEPL, Trunkline and Sea Robin transmission systems, serves customers in the Midwest, Gulf Coast and Midcontinent United States with a comprehensive array of transportation and storage services. In connection with its natural gas pipeline transmission and storage systems, Panhandle has five natural gas storage fields located in Illinois, Kansas, Louisiana, Michigan and Oklahoma. Southwest Gas operates four of these fields and Trunkline operates one.

As discussed above in “Significant Organic Growth Projects,” we are currently developing plans to convert a portion of the Trunkline gas pipeline to crude oil transportation.

The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services. The major customers on our interstate pipelines include BG Energy Holdings Ltd., Chesapeake Energy Marketing, Inc., Ameren Corporation, EnCana Marketing (USA), Inc., and Petrohawk Energy Corporation.

Midstream Segment

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 is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

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

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 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.

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.

Through our midstream segment, we own and operate approximately 6,700 miles of in service natural gas and NGL gathering pipelines with approximately 6.0 Bcf/d of gathering capacity, 5 natural gas processing plants, 15 natural gas treating facilities and 3 natural gas conditioning facilities with an aggregate processing, treating and conditioning capacity of approximately 4.2 Bcf/d. Our midstream segment focuses on the gathering, compression, treating, blending, and processing, 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 and Woodford Shale in North Texas, the Bossier Sands in East Texas, 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. The major customers on our midstream pipelines include Enterprise Products Operating LLC, ONEOK Hydrocarbon, L.P., Formosa Hydrocarbons Company, Inc., Chevron Phillips Chemical Company LP, and Phillips 66 Company.

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NGL Transportation and Services Segment

NGL transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities. 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 fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.

Through our NGL transportation and services segment we have a 70% interest in Lone Star, which owns approximately 2,000 miles of NGL pipelines with an aggregate transportation capacity of approximately 388,000 Bbls/d, three NGL processing plants with an aggregate processing capacity of approximately 904 MMcf/d, three fractionation facilities with an aggregate capacity of 251,000 Bbls/d and NGL storage facilities with aggregate working storage capacity of approximately 47 million Bbls. Two fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, one fractionation facility is located in Geismar, Louisiana, and the NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu. We also own and operate approximately 274 miles of NGL pipelines including a 50% interest in the joint venture that owns the Liberty pipeline, an approximately 87-mile NGL pipeline.

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 Enterprise Products Operating LLC, Targa Resources Partners LP, BP Energy Company, Dow Hydrocarbons and Resources LLC, and BP Products North America Inc.

Investment in Sunoco Logistics Segment

The Partnership's interests in Sunoco Logistics consist of a 2% general partner interest, 100% of the IDRs and 33.5 million Sunoco Logistics common units representing 32% of the limited partner interests in Sunoco Logistics as of

December 31, 2013. Because the Partnership controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into the Partnership. These operations are reflected by the Partnership in the investment in Sunoco Logistics segment.

Sunoco Logistics owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets which are used to facilitate the purchase and sale of crude oil and refined petroleum products pipelines primarily in the northeast, midwest and southwest regions of the United States. In 2013, Sunoco Logistics initiated the expansion of its operations into the pipeline transportation, acquisition, storage and marketing of NGLs. In addition, Sunoco Logistics has ownership interests in several refined product pipeline joint ventures.

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Sunoco Logistics' crude oil pipelines transport crude oil principally in Oklahoma and Texas. Sunoco Logistics' crude oil pipelines consist of approximately 4,900 miles of crude oil trunk pipelines and approximately 500 miles of crude oil gathering lines that supply the trunk pipelines.

Sunoco Logistics' crude oil acquisition and marketing business gathers, purchases, markets and sells crude oil principally in the mid-continent United States, utilizing its fleet of approximately 300 crude oil transport trucks, approximately 130 crude oil truck unloading facilities as well as third-party assets.

Sunoco Logistics' refined products terminals receive refined products from pipelines, barges, railcars, and trucks and distribute them to third parties and certain affiliates, who in turn deliver them to end-users and retail outlets. Sunoco Logistics' terminal facilities operate with an aggregate storage capacity of approximately 46 million barrels, including the 22 million barrel Nederland, Texas crude oil terminal; the 5 million barrel Eagle Point, New Jersey refined products and crude oil terminal; the 5 million barrel Marcus Hook, Pennsylvania refined products and NGL facility; approximately 39 active refined products marketing terminals located in the northeast, midwest and southwest United States; and several refinery terminals located in the northeast United States.

Sunoco Logistics' refined product pipelines transport refined products including multiple grades of gasoline, middle distillates (such as heating oil, diesel and jet fuel) and LPGs (such as propane and butane) from refineries to markets. Sunoco Logistics' refined products pipelines consist of approximately 2,500 miles of refined product pipelines and joint venture interests in four refined products pipelines in selected areas of the United States.

Retail Marketing Segment

Our retail marketing and wholesale distribution business segment consists of the following:

- Retail marketing operations consist of the sale of gasoline and middle distillates at retail locations and operation of convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States. The highest concentrations of outlets are located in Connecticut, Florida, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Virginia.
- Sunoco also engages in the distribution of gasoline (including gasoline blendstocks such as ethanol), distillates, and other petroleum products to wholesalers, retailers and other commercial customers.

All Other Segment

Segments below the quantitative thresholds are classified as "All other." These include the following:

- 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 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.
- We own common units in AmeriGas, a publicly traded master limited partnership engaged in retail propane marketing. We acquired this interest when we contributed our retail propane operations to AmeriGas in January 2012. As of December 31, 2013, we owned common units representing approximately 24% of AmeriGas' outstanding common units and, following a sale of a portion of these units in a public offering in January 2014, we own 12.9 million AmeriGas common units representing approximately 14% of AmeriGas' outstanding common units.
- Southern Union previously had operations providing local distribution of natural gas in Missouri and Massachusetts. The operations were conducted through the Southern Union's operating divisions: MGE and NEG. Both of these operating divisions were sold in 2013.
- Sunoco owns an approximate 33% non-operating interest in PES, a refining joint venture with The Carlyle Group, L.P. ("The Carlyle Group"), which owns a refinery in Philadelphia. Sunoco has a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.
- We own an investment in Regency related to the Regency common and Class F units received by Southern Union in exchange of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013.
- 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

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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.

Asset Overview

Intrastate Transportation and Storage

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 2,870 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 prolific production areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. The ET Fuel System has many interconnections with pipelines providing direct access to power plants, other intrastate, and interstate pipelines and is strategically located near high-growth production areas and provides access to the Waha Hub near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas.

The ET Fuel System 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 extend through 2015.

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
- Bi-directional capabilities

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 5.3 Bcf/d
- Approximately 3,900 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

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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, 2013, we had approximately 7.2 Bcf committed under fee-based arrangements with third parties and approximately 45.8 Bcf stored in the facility for our own account.
We are currently converting approximately 84 miles of pipeline from the HPL System to crude service. This project is expected to be completed in 2014.
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.
Interstate Transportation and Storage
The following details our pipelines in the interstate transportation and storage segment.
Florida Gas Transmission Pipeline
- Capacity of 3.1 Bcf/d
- Approximately 5,400 miles of interstate natural gas pipeline
- FGT is owned by Citrus, a 50/50 joint venture with Kinder Morgan, Inc. (“KMI”)

The Florida Gas Transmission pipeline is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,400 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The Florida Gas Transmission pipeline system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering over 63% of the natural gas consumed in the state. In addition, Florida Gas Transmission’s pipeline system operates and maintains over 75 interconnects with major interstate and intrastate natural gas pipelines, which provide FGT’s customers access to diverse natural gas producing regions.
FGT’s customers include electric utilities, independent power producers, industrials and local distribution companies.
Transwestern Pipeline
- Capacity of 2.1 Bcf/d
- Approximately 2,600 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.

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Panhandle Eastern Pipe Line
- Capacity of 2.8 Bcf/d
- Approximately 6,000 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Panhandle Eastern Pipe Line's transmission system consists of four large diameter pipelines extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. Panhandle Eastern Pipe Line is owned by a subsidiary of Holdco.

Trunkline Gas Pipeline
- Capacity of 1.7 Bcf/d
- Approximately 3,000 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Trunkline Gas pipeline's transmission system consists of two large diameter pipelines extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and to Michigan. Trunkline Gas pipeline is owned by a subsidiary of Holdco.

As discussed above in "Significant Organic Growth Projects," we are currently developing plans to convert a portion of the Trunkline gas pipeline to crude oil transportation.

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 through ETC FEP 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.

Sea Robin Pipeline
- Capacity of 2.3 Bcf/d
- Approximately 1,000 miles of interstate natural gas pipeline

The Sea Robin pipeline's transmission system consists of two offshore Louisiana natural gas supply systems extending approximately 120 miles into the Gulf of Mexico.

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Midstream

The following details our assets in the midstream segment.

Southeast Texas System

- Approximately 5,900 miles of natural gas pipeline
- One natural gas processing plant (La Grange) with aggregate capacity of 210 MMcf/d
- 11 natural gas treating facilities with aggregate capacity of 1.4 Bcf/d
- One natural gas conditioning facility with aggregate capacity of 200 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 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.

The La Grange processing plant is a natural gas processing plant that processes the rich natural gas that flows through our system to produce residue gas and NGLs. Residue gas is delivered into our intrastate pipelines and NGLs are delivered into our recently acquired or completed pipelines.

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 700 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 and Woodford Shales. 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 processing plant and a conditioning facility.

Northern Louisiana

- Approximately 280 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.

Eagle Ford System

- Approximately 245 miles of natural gas pipeline
- Three processing plants (Chisholm, Kenedy and Jackson) with capacity of 920 MMcf/d
- One natural gas treating facility with capacity of 300 MMcf/d

The Eagle Ford gathering system consists of 30-inch and 42-inch natural gas transportation pipelines delivering 1.4 Bcf/d of capacity originating in Dimmitt County, Texas and extending to our Chisholm pipeline for ultimate deliveries to our existing processing plants. Our Chisholm, Kenedy and Jackson processing plants are connected to our intrastate transportation pipeline systems for deliveries of residue gas and are also connected with our NGL pipelines for delivery of NGLs.

Other Midstream Assets

The midstream segment also includes our interests in various midstream assets located in Texas, New Mexico and Louisiana, with approximately 60 miles of gathering pipelines aggregating a combined capacity of approximately 115 MMcf/d, as well as one

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conditioning facility. We also own approximately 35 miles of gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

NGL Transportation and Services

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

West Texas System

- Capacity of 137,000 Bbls/d
- Approximately 1,070 miles of NGL transmission pipelines

The West Texas System, owned by Lone Star, 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 processing plants in the Permian Basin and Barnett Shale to the Mont Belvieu NGL storage facility.

West Texas Gateway Pipeline

- Capacity of 209,000 Bbls/d
- Approximately 570 miles of NGL transmission pipeline

The West Texas Gateway Pipeline, owned by Lone Star, began service in December 2012 and transports NGLs produced in the Permian and Delaware Basins and the Eagle Ford Shale to Mont Belvieu, Texas.

Other NGL Pipelines

- Aggregate capacity of 490,000 Bbls/d
- Approximately 274 miles of NGL transmission pipelines

Other NGL pipelines include the 127-mile Justice pipeline with capacity of 340,000 Bbls/d, the 87-mile Liberty pipeline with a capacity of 90,000 Bbls/d, the 45-mile Freedom pipeline with a capacity of 40,000 Bbls/d and the 15-mile Spirit pipeline with a capacity of 20,000 Bbls/d.

Mont Belvieu Facilities

- Working storage capacity of approximately 43 million Bbls
- Approximately 185 miles of NGL transmission pipelines
- 200,000 Bbls/d fractionation facilities

The Mont Belvieu storage facility, owned by Lone Star, 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.

The Lone Star Fractionators I and II, completed in December 2012 and November 2013, respectively, handle NGLs delivered from several sources, including Lone Star's West Texas Gateway pipeline and the Justice pipeline.

Hattiesburg Storage Facility

- Working storage capacity of approximately 4 million Bbls

The Hattiesburg storage facility, owned by Lone Star, is an integrated liquids storage facility with approximately 4 million Bbls of salt dome capacity, providing 100% fee-based cash flows.

Sea Robin Processing Plant

- One processing 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 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.

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Refinery Services

- Two processing plants (Chalmette and Sorrento) with capacity of 54 MMcf/d
- One NGL fractionator with 25,000 Bbls/d capacity
- Approximately 100 miles of NGL pipelines

Refinery Services, owned by Lone Star, 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 Chalmette processing plant.

Investment in Sunoco Logistics

The following details our assets in the investment in Sunoco Logistics segment.

Crude Oil Pipelines

Sunoco Logistics' crude oil pipelines consist of approximately 4,900 miles of crude oil trunk pipelines and approximately 500 miles of crude oil gathering pipelines in the southwest and midwest United States. These lines primarily deliver crude oil and other feedstocks to refineries in those regions. Following is a description of Sunoco Logistics' crude pipelines:

- Southwest United States: The Southwest United States pipeline system includes approximately 2,950 miles of crude oil trunk pipelines and approximately 300 miles of crude oil gathering pipelines in Texas. The Texas system includes the West Texas Gulf Pipe Line Company's 600 miles of common carrier crude oil pipelines, which originate from the West Texas oil fields at Colorado City, Texas and is connected to the Mid-Valley pipeline, other third-party pipelines and the Nederland Terminal.

The Southwest United States pipeline system also includes the Oklahoma crude oil pipeline and gathering system that consists of approximately 850 miles of crude oil trunk pipelines and approximately 200 miles of crude oil gathering pipelines. Sunoco Logistics has the ability to deliver substantially all of the crude oil gathered on the Oklahoma system to Cushing, Oklahoma and is one of the largest purchasers of crude oil from producers in the state.

- Midwest United States: The Midwest United States pipeline system includes Sunoco Logistics' majority interest in the Mid-Valley Pipeline Company and consists of approximately 1,000 miles of a crude oil pipeline that originates in Longview, Texas and passes through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky and Ohio, and terminates in Samaria, Michigan. This pipeline provides crude oil to a number of refineries, primarily in the midwest United States.

Sunoco Logistics also owns approximately 100 miles of crude oil pipeline that runs from Marysville, Michigan to Toledo, Ohio, and a truck injection point for local production at Marysville. This pipeline receives crude oil from the Enbridge pipeline system for delivery to refineries located in Toledo, Ohio and to Marathon's Samaria, Michigan tank farm, which supplies its refinery in Detroit, Michigan.

Crude Oil Acquisition and Marketing

Sunoco Logistics' crude oil acquisition and marketing activities include the gathering, purchasing, marketing and selling of crude oil primarily in the mid-continent United States. The operations are conducted using approximately 300 crude oil transport trucks, approximately 130 crude oil truck unloading facilities, as well as third-party assets. Sunoco Logistics' crude oil truck drivers pick up crude oil at production lease sites and transport it to various truck unloading facilities on its pipelines and third-party pipelines. Third-party trucking firms are also retained to transport crude oil to certain facilities. Specifically, the crude oil acquisition and marketing activities include:

- purchasing crude oil at the wellhead from producers, and in bulk from aggregators at major pipeline interconnections and trading locations;
- storing inventory during contango market conditions (when the price of crude oil for future delivery is higher than current prices);
- buying and selling crude oil of different grades, at different locations in order to maximize value for producers;
- transporting crude oil on our pipelines and trucks or, when necessary or cost effective, pipelines or trucks owned and operated by third parties; and
- marketing crude oil to major integrated oil companies, independent refiners and resellers through various types of sale and exchange transactions.

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Terminal Facilities

Sunoco Logistics' 39 active refined products terminals receive refined products from pipelines, barges, railcars, and trucks and distribute them to Sunoco and to third parties, who in turn deliver them to end-users and retail outlets. Terminals are facilities where products are transferred to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. The operation of these facilities is called "terminalling."

Terminals play a key role in moving product to the end-user markets by providing the following services: storage; distribution; blending to achieve specified grades of gasoline and middle distillates; and other ancillary services that include the injection of additives and the filtering of jet fuel. Typically, Sunoco Logistics' refined products terminal facilities consist of multiple storage tanks and are equipped with automated truck loading equipment that is operational 24 hours a day. This automated system provides controls over allocations, credit, and carrier certification.

- Nederland Terminal: The Nederland Terminal, which is located on the Sabine-Neches waterway between Beaumont and Port Arthur, Texas, is a large marine terminal providing storage and distribution services for refiners and other large transporters of crude oil. The terminal receives, stores, and distributes crude oil, feedstocks, lubricants, petrochemicals, and bunker oils (used for fueling ships and other marine vessels), and also blends lubricants. The terminal currently has a total storage capacity of approximately 22 million barrels in approximately 130 above ground storage tanks with individual capacities of up to 660,000 barrels.

The Nederland Terminal can receive crude oil at each of its five ship docks and three barge berths. The five ship docks are capable of receiving over 2 million Bbls/d of crude oil. In addition to our Crude Oil Pipelines, the terminal can also receive crude oil through a number of other pipelines, including: the Cameron Highway pipeline, which is jointly owned by Enterprise Products and Genesis Energy; the ExxonMobil Pegasus pipeline; the Department of Energy ("DOE") Big Hill pipeline; and the DOE West Hackberry pipeline. The DOE pipelines connect the terminal to the United States Strategic Petroleum Reserve's West Hackberry caverns at Hackberry, Louisiana and Big Hill near Winnie, Texas, which have an aggregate storage capacity of approximately 400 million barrels.

The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge, ship, rail, or truck. In total, the terminal is capable of delivering over 2 million Bbls/d of crude oil to Sunoco Logistics' crude oil pipelines or a number of third-party pipelines including: the ExxonMobil pipeline to its Beaumont, Texas refinery; the DOE pipelines to the Big Hill and West Hackberry Strategic Petroleum Reserve caverns; the Valero pipeline to its Port Arthur, Texas refinery; and the Total pipelines to its Port Arthur, Texas refinery.

- Fort Mifflin Terminal Complex: The Fort Mifflin Terminal Complex is located on the Delaware River in Philadelphia, Pennsylvania and includes the Fort Mifflin Terminal, the Hog Island Wharf, the Darby Creek tank farm and connecting pipelines. Revenues are generated from the Fort Mifflin Terminal Complex by charging fees based on throughput. The Fort Mifflin Terminal contains two ship docks with 40-foot freshwater drafts and a total storage capacity of approximately 570,000 barrels. Crude oil and some refined products enter the Fort Mifflin Terminal primarily from marine vessels on the Delaware River. One Fort Mifflin dock is designed to handle crude oil from very large crude carrier-class ("VLCC") tankers and smaller crude oil vessels. The other dock can accommodate only smaller crude oil vessels. In September 2012, Sunoco completed the formation of PES, a joint venture with The Carlyle Group. In connection with this transaction, Sunoco Logistics entered into a ten-year agreement to provide terminalling services to PES at the Fort Mifflin Terminal Complex.

The Hog Island Wharf is located next to the Fort Mifflin Terminal on the Delaware River and receives crude oil via two ship docks, one of which can accommodate crude oil tankers and smaller crude oil vessels, and the other of which can accommodate some smaller crude oil vessels.

The Darby Creek tank farm is a primary crude oil storage terminal for the Philadelphia refinery. This facility has a total storage capacity of approximately 3 million barrels. Darby Creek receives crude oil from the Fort Mifflin Terminal and Hog Island Wharf via Sunoco Logistics pipelines. The tank farm then stores the crude oil and transports it to the PES refinery via Sunoco Logistics pipelines.

- Marcus Hook Facility: In 2013, Sunoco Logistics acquired Sunoco's Marcus Hook facility and related assets. The acquisition included terminalling and storage assets with a capacity of approximately 5 million barrels located in Pennsylvania and Delaware, including approximately 2 million barrels of NGL storage capacity in underground caverns, and related commercial agreements. The facility can receive NGLs via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. In addition to providing NGL storage and terminalling services to both affiliates and third-party customers, the Marcus Hook facility also provides customers with the use of industrial space and equipment at the facility, as well as logistical, utility and infrastructure services.

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The Marcus Hook tank farm has a total storage capacity of approximately 2 million barrels. The terminal generates revenue from throughput and storage, and delivers and receives refined products via pipeline. Sunoco Logistics utilizes the tank farm assets to provide terminalling services and to support movements on its refined products pipelines.

- Eagle Point Terminal: The Eagle Point Terminal is located in Westville, New Jersey and consists of docks, truck loading facilities and a tank farm. The docks are located on the Delaware River and can accommodate three ships or barges to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges. The tank farm has a total active storage capacity of approximately 5 million barrels and can receive crude oil and refined products via barge, pipeline and rail. The terminal can deliver via barge, truck, rail or pipeline, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage for clean products and dark oils.
- Inkster Terminal: The Inkster Terminal, located near Detroit, Michigan, consists of eight salt caverns with a total storage capacity of approximately 975,000 barrels. The Inkster Terminal's storage is used in connection with the Toledo, Ohio to Sarnia, Canada pipeline system and for the storage of LPGs from Canada and a refinery in Toledo. The terminal can receive and ship LPGs in both directions at the same time and has a propane truck loading rack.

The following table outlines the number of Sunoco Logistics' active terminals and storage capacity by state:

State	Number of Terminals	Storage Capacity (thousands of Bbls)
Indiana	1	206
Louisiana	1	161
Maryland	1	710
Massachusetts	1	1,144
Michigan	3	760
New Jersey	3	650
New York[(1)]	4	920
Ohio	7	957
Pennsylvania	13	1,743
Texas	4	548
Virginia	1	403
Total	39	8,202

(1) Sunoco Logistics has a 45% ownership interest in a terminal at Inwood, New York and a 50% ownership interest in a terminal at Syracuse, New York. The storage capacities included in the table represent the proportionate share of capacity attributable to Sunoco Logistics' ownership interests in these terminals.

Refined Products Pipelines

Sunoco Logistics owns and operates approximately 2,500 miles of refined products pipelines in several regions of the United States. The refined products pipelines primarily transport refined products from refineries in the northeast, midwest and southwest United States to markets in New York, New Jersey, Pennsylvania, Ohio, Michigan and Texas. These pipelines include approximately 350 miles of pipelines owned by our consolidated joint venture, Inland.

The refined products transported in these pipelines include multiple grades of gasoline, middle distillates (such as heating oil, diesel and jet fuel), and LPGs (such as propane and butane). In addition, certain of these pipelines transport NGLs from processing and fractionation areas to marketing and distribution facilities. Rates for shipments on the refined products pipelines are regulated by the FERC and the Pennsylvania Public Utility Commission ("PA PUC"), among other state regulatory agencies.

- Inland Corporation: Inland Corporation ("Inland") is Sunoco Logistics' 83.8% owned joint venture consisting of approximately 350 miles of active refined products pipelines in Ohio. The pipeline connects three refineries in Ohio to terminals and major markets within the state. As Sunoco Logistics owns a controlling financial interest in Inland, the joint venture is reflected as a consolidated subsidiary in its consolidated financial statements.

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Sunoco Logistics owns equity interests in several common carrier refined products pipelines, summarized in the following table:

Pipeline	Equity Ownership		Pipeline Mileage
Explorer Pipeline Company[1]	9.4	%	1,850
Yellowstone Pipe Line Company[2]	14.0	%	700
West Shore Pipe Line Company[3]	17.1	%	650
Wolverine Pipe Line Company[4]	31.5	%	700

(1) The system, which is operated by Explorer employees, originates from the refining centers of Beaumont, Port Arthur and Houston, Texas, and extends to Chicago, Illinois, with delivery points in the Houston, Dallas/Fort Worth, Tulsa, St. Louis, and Chicago areas. Explorer charges market-based rates for all its tariffs.

(2) The system, which is operated by Phillips 66, originates from the Billings, Montana refining center and extends to Moses Lake, Washington with delivery points along the way. Tariff rates are regulated by the FERC for interstate shipments and the Montana Public Service Commission for intrastate shipments in Montana.

(3) The system, which is operated by Buckeye Partners, L.P., originates from the Chicago, Illinois refining center and extends to Madison and Green Bay, Wisconsin with delivery points along the way. West Shore charges market-based tariff rates in the Chicago area.

(4) The system, which is operated by Wolverine employees, originates from Chicago, Illinois and extends to Detroit, Grand Haven, and Bay City, Michigan with delivery points along the way. Wolverine charges market-based rates for tariffs at the Detroit, Jackson, Niles, Hammond, and Lockport destinations.

Retail Marketing

The retail marketing segment consists of the retail sale of gasoline and middle distillates and the operation of Sunoco and MACS convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States. The highest concentrations of outlets are located in Connecticut, Florida, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Virginia.

Retail marketing has a portfolio of outlets that differ in various ways including: product distribution to the outlets; site ownership and operation; and types of products and services provided.

Direct outlets may be operated by Sunoco (either directly or through a wholly-owned subsidiary of ETC OLP) or by an independent dealer, and are sites at which fuel products are delivered directly to the site by Sunoco trucks or by contract carriers. Sunoco or an independent dealer owns or leases the property. Some of these sites may be traditional locations that sell fuel products under the Sunoco®, Exxon®, Mobil® and Coastal® brands. The site may also include an APlus® or Circle K® convenience store or Ultra Service Centers® that provide automotive diagnostics and repair. Included among the direct outlets at December 31, 2013 were 74 outlets on turnpikes and expressways in Pennsylvania, New Jersey, New York, Maryland, Ohio and Delaware. Of these outlets, 59 were Sunoco-operated sites providing gasoline, diesel fuel and convenience store merchandise.

Distributor outlets are sites in which the distributor takes delivery of fuel products at a terminal where branded products are available. Sunoco does not own, lease or operate these locations.

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The following table sets forth our retail gasoline outlets at December 31, 2013 (including sites operated through Sunoco and a wholly-owned subsidiary of ETC OLP):

Direct Outlets:	
Company-Owned or Leased:	
Company Operated:	
Traditional	66
APlus® and Circle K® Convenience Stores	447
	513
Dealer Operated:	
Traditional	252
APlus® and Circle K® Convenience Stores	241
Ultra Service Centers®	83
	576
Total Company-Owned or Leased[1]	1,089
Dealer Owned[2]	525
Total Direct Outlets	1,614
Distributor Outlets	3,498
	5,112

[1] Gasoline and diesel throughput per company-operated site averaged 200,087 gallons per month during 2013.
[2] Primarily traditional outlets.

Sunoco's branded fuels sales (including middle distillates) averaged 315,700 Bbls/d in 2013.

The Sunoco® brand is positioned as a premium brand. Brand improvements in recent years have focused on physical image, customer service and product offerings. In addition, Sunoco believes its brands and high performance gasoline business have benefited from its sponsorship agreements with NASCAR® and INDYCAR®. Under the sponsorship agreement with NASCAR, which continues until 2019, Sunoco® is the Official Fuel of NASCAR® and APlus® is the Official Convenience Store of NASCAR®. Sunoco has exclusive rights to use certain NASCAR® trademarks to advertise and promote Sunoco products and is the exclusive fuel supplier for the three major NASCAR® racing series. Sunoco has an agreement to be the Official Fuel of the INDYCAR® series through the 2014 season.

Sunoco's APlus® convenience stores are located principally in Florida, New York and Pennsylvania. These stores supplement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products. The following table sets forth information concerning Sunoco's company-operated APlus® convenience stores at December 31, 2013:

Number of stores	384	
Merchandise sales (thousands of dollars/store/month)	$108	
Merchandise margin (% sales)	26.8	%

The retail marketing segment also includes the distribution of gasoline, distillates, and other petroleum products to wholesalers, unbranded retailers and other commercial customers.

Business Strategy

We have designed our business strategy with the goal of creating and maximizing value to our Unitholders. We believe we have engaged, and will continue to engage, in a well-balanced plan for growth through strategic acquisitions, internally generated expansion, measures aimed at increasing the profitability of our existing assets and executing cost control measures where appropriate to manage our operations.

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 we will be best positioned to achieve our objectives. We balance our desire for growth with our goal of preserving a strong balance sheet, ample liquidity and investment grade credit metrics.

Following is a summary of the business strategies of our core 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 that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing assets while supporting our investment grade credit ratings.

Competition

Natural Gas

The business of providing natural gas gathering, compression, treating, transportation, storage 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 other 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.

NGL

In markets served by our NGL pipelines, we face competition with other pipeline companies, including those affiliated with major oil, petrochemical and natural gas companies, and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees, reliability and quality of customer service. We face competition with other storage facilities based on fees charged and the ability to receive and distribute the customer’s products. We compete with a number of NGL fractionators in Texas and Louisiana. Competition for such services is primarily based on the fractionation fee charged.

Crude Oil and Refined Products

In markets served by our refined products and crude oil pipelines, we face competition from other pipelines. Generally, pipelines are the lowest cost method for long-haul, overland movement of refined products. Therefore, the most significant competitors for large volume shipments in the areas served by our pipelines are other pipelines. In addition, pipeline operations face competition from trucks that deliver product in a number of areas that our pipeline operations serve. While their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and marginal volume in many areas served by our pipelines.

We also face competition among common carrier pipelines carrying crude oil. This competition is based primarily on transportation charges, access to crude oil supply and market demand. Similar to pipelines carrying refined products, the high capital costs deter competitors for the crude oil pipeline systems from building new pipelines. Competitive factors in crude oil purchasing and marketing include price and contract flexibility, quantity and quality of services, and accessibility to end markets.

Our refined product terminals compete with other independent terminals with respect to price, versatility and services provided. The competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

Retail Marketing

We face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations of large integrated oil companies, independent gasoline service stations, convenience stores, fast food stores, and other similar retail outlets, some of which are well-recognized national or regional retail systems. The number of competitors varies depending on the geographical area. It also varies with gasoline and convenience store offerings. The principal competitive factors affecting our retail marketing operations include gasoline and diesel acquisition costs, site location, product price, selection and quality, site appearance and cleanliness, hours of operation, store safety, customer loyalty and brand recognition. We compete by pricing gasoline competitively, combining retail gasoline business with convenience stores that provide a wide variety of products, and using advertising and promotional campaigns. We believe that we are in a position to compete effectively as a marketer of refined products because of the location of our retail network, which is well integrated with the distribution system operated by Sunoco Logistics.

Credit Risk and Customers

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. The discovery and development of new shale formations across the United States has created an abundance of natural gas resulting in a negative impact on prices in recent years. As a result, some of our exploration and production customers have been negatively impacted; however, we are monitoring these customers and mitigating credit risk as necessary.

During the year ended December 31, 2013, none of our customers individually accounted for more than 10% of our consolidated revenues.

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 Florida Gas Transmission, Transwestern, Panhandle Eastern, Trunkline Gas, Tiger, Fayetteville Express and Sea Robin pipelines transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain storage facilities that are subject to the FERC's 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.

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.

In 2011, in lieu of filing a new NGA Section 4 general 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 we were required to reduce 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 October 1, 2014.

The rates charged for services on the Fayetteville Express pipeline are largely governed by long-term negotiated rate agreements. The FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates.

The rates charged for services on the Tiger pipeline are largely governed by long-term negotiated rate agreements.

In July 2010, in response to an intervention and protest filed by BG LNG Services ("BGLS") regarding its rates with Trunkline LNG applicable to certain LNG expansions, the FERC determined that there was no reason at that time to expend the FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided to the FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. The current fixed rates expire at the end of 2015 and revert to tariff rate for these LNG expansions as well as the base LNG facilities for which rates were set in 2002.

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 and 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 and 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

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charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC review and approval. Should 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.

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the 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.

Our NGL pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities.

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 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 and West Virginia 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 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, the courts and Congress. 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

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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 Interstate Crude Oil and Refined Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act (“ICA”), the Energy Policy Act of 1992, and related rules and orders. The ICA requires that tariff rates for petroleum pipelines be “just and reasonable” and not unduly discriminatory and that such rates and terms and conditions of service be filed with the FERC. This statute also permits interested persons to challenge proposed new or changed rates. The FERC is authorized to suspend the effectiveness of such rates for up to seven months, though rates are typically not suspended for the maximum allowable period. If the FERC finds that the new or changed rate is unlawful, it may require the carrier to pay refunds for the period that the rate was in effect. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint. The FERC generally has not investigated interstate rates on its own initiative when those rates, like those we charge, have not been the subject of a protest or a complaint by a shipper. However, the FERC could investigate our rates at the urging of a third party if the third party is either a current shipper or has a substantial economic interest in the tariff rate level. Although no assurance can be given that the tariffs charged by us ultimately will be upheld if challenged, management believes that the tariffs now in effect for our pipelines are within the maximum rates allowed under current FERC guidelines.

We have been approved by the FERC to charge market-based rates in most of the refined products locations served by our pipeline systems. In those locations where market-based rates have been approved, we are able to establish rates that are based upon competitive market conditions.

Regulation of Intrastate Crude Oil and Refined Products Pipelines. Some of our crude oil and refined products pipelines are subject to regulation by the TRRC, the PA PUC, and the Oklahoma Corporation Commission. The operations of our joint venture interests are also subject to regulation in the states in which they operate. The applicable state statutes require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services. State commissions generally have not initiated an investigation of rates or practices of petroleum pipelines in the absence of shipper complaints. Complaints to state agencies have been infrequent and are usually resolved informally. Although management cannot be certain that our intrastate rates ultimately would be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if challenged, are not likely to be ordered to be reduced.

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the DOT, under the PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (“HLPSA”), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 (“PSI Act”) and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (“PIPES Act”). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs"), which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. 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.

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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 or PHMSA including changes to the "rural gathering exemption," which may be restricted in the future. While we believe our pipeline operations are in substantial compliance with applicable pipeline safety laws, safety laws and 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.

Most recently, these pipeline safety laws were amended on January 3, 2012 when President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") which 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 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.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which we conduct operations typically have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. Under such state regulatory programs, states have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, PHMSA and individual states may pass or implement additional safety requirements that could result in increased compliance costs for us and other companies in our industry. For instance, notwithstanding the applicability of the OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Planning ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in the recent past, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. These recent actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such legal challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Environmental Matters

General. Our operation of processing plants, pipelines and associated facilities, including compression, in connection with the gathering, processing, storage and transmission of natural gas and the storage and transportation of NGLs, crude oil and refined products is subject to stringent federal, state and local laws and regulations, including those governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall cost of doing business, including our cost of planning, constructing and operating our plants, pipelines and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade our equipment and facilities to remain in compliance with environmental laws and regulations.

We have implemented procedures to ensure that all governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our business, results of operations and financial condition. We cannot be certain, however, that identification of presently unidentified conditions, more rigorous enforcement by regulatory agencies, enactment of more stringent environmental laws and regulations or other unanticipated events will not arise in the future and give rise to environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

Hazardous Substances and Waste Materials. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances and waste materials into soils, groundwater and surface water and include measures to prevent, minimize or remediate contamination of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of hazardous substances and waste materials and may require investigatory and remedial actions at sites where such material has been released or disposed. For example, CERCLA, also known as the “Superfund” law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a “hazardous substance” into the environment. These persons include the owner and operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substance that has been released into the environment. Under CERCLA, these persons may be subject to joint and several liability, without regard to fault, for, among other things, the costs of investigating and remediating the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and comparable state law also authorize the federal EPA, its state counterparts, and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although “petroleum” as well as natural gas and NGLs are excluded from CERCLA’s definition of a “hazardous substance,” in the course of our ordinary operations we generate wastes that may fall within that definition or that may be subject to other waste disposal laws and regulations. We may be responsible under CERCLA or state laws for all or part of the costs required to clean up sites at which such substances or wastes have been disposed.

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal Resource Conservation and Recovery Act (“RCRA”), and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent management standards. From time to time, the EPA has considered the adoption of stricter handling, storage and disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as “hazardous wastes,” resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes such as these examples in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense.

We currently own or lease sites that have been used over the years by prior owners and by us for various activities related to gathering, processing, storage and transmission of natural gas, NGLs, crude oil and refined products. Solid waste disposal practices within the oil and gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or otherwise released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these releases may have occurred during the ownership of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of contamination.

As of December 31, 2013 and 2012, accruals of $395 million and $211 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, the predecessor owner’s share of certain environmental liabilities of ETC OLP.

The Partnership is subject to extensive and frequently changing federal, state and local laws and regulations, including, but not limited to, those relating to the discharge of materials into the environment or that otherwise relate to the protection of the environment, waste management and the characteristics and composition of fuels. These laws and regulations require environmental assessment and/or remediation efforts at many of Sunoco’s facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $377 million at December 31, 2013, which is included in the total accruals above. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that are no longer operated by Sunoco, closed and/or sold refineries and other formerly owned sites. In December 2013, a wholly-owned captive insurance company was established for these legacy sites. As of December 31, 2013 the captive insurance company held $348 million of cash, which was reported as restricted funds.

The Partnership's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual for known claims is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities.

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We have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.
Under various environmental laws, including the RCRA (which relates to solid and hazardous waste treatment, storage and disposal), the Partnership has initiated corrective remedial action at its facilities, formerly owned facilities and third-party sites. At the Partnership's major manufacturing facilities, we have consistently assumed continued industrial use and a containment/remediation strategy focused on eliminating unacceptable risks to human health or the environment. The remediation accruals for these sites reflect that strategy. Accruals include amounts to prevent off-site migration and to contain the impact on the facility property, as well as to address known, discrete areas requiring remediation within the plants. Activities include closure of RCRA solid waste management units, recovery of hydrocarbons, handling of impacted soil, mitigation of surface water impacts and prevention of off-site migration. A change in this approach as a result of changing the intended use of a property or a sale to a third party could result in a higher cost remediation strategy in the future.
The Partnership currently owns or operates certain retail gasoline outlets where releases of petroleum products have occurred. Federal and state laws and regulations require that contamination caused by such releases at these sites and at formerly owned sites be assessed and remediated to meet the applicable standards. Our obligation to remediate this type of contamination varies, depending on the extent of the release and the applicable laws and regulations. A portion of the remediation costs may be recoverable from the reimbursement fund of the applicable state, after any deductible has been met.
In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. The estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded.
In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (i.e., less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2013, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $6 million. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets, and in many cases, reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.
In summary, total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years. Management believes that the Partnership's exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such

charges would have a material adverse impact on the Partnership's consolidated financial position.
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 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 $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.

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Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will be required to incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. We believe that our operations are in substantial compliance with the federal Clean Air Act and comparable state laws.
The EPA and state agencies are continually considering, proposing or finalizing new rules and regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, EPA has recently finalized new source performance standards (NSPS) for the oil and gas source category. New Subpart OOOO expands the NSPS oil and gas source category to include all segments of the oil and gas industry. It imposes new controls for emissions of volatile organic compounds (VOCs) on well completions, pneumatic devices, compressors, storage vessels and equipment leaks. In addition, EPA has also recently finalized revisions to Subparts HH and HHH that will further reduce emissions of hazardous air pollutants from storage tanks and tri-ethylene glycol dehydrators at major sources. These new regulations will increase our cost of compliance.
On October 19, 2010, the EPA adopted new national emission standards for hazardous air pollutants for existing stationary spark ignition reciprocating internal combustion engines that are either located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions. All engines subject to these “Quad Z” regulations were required to comply by October 19, 2013. Many of our facilities, including our leased compressors have been impacted by these new rules. We have incurred increased costs to bring engines into compliance with the new emission requirements, but such costs were not material.
Clean Water Act. The Federal Water Pollution Control Act of 1972, also known as Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that our continued compliance with such existing permit conditions will not have a material adverse effect on our business, financial condition or results of operations.
Spills. Our operations can result in the discharge of regulated substances, including NGLs, crude oil or refined products. The Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of regulated substances into state waters or waters of the United States. The Clean Water Act and comparable state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges. The Oil Pollution Act subjects owners of covered facilities to strict joint and potentially unlimited liability for removal costs and other consequences of a release of oil, where the release is into navigable waters, along shorelines or in the exclusive economic zone of the United States. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require that containment dikes and similar structures be installed to help prevent the impact on navigable waters in the event of a release. The Office of Pipeline Safety of the DOT, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans, and our management believes we are in substantial compliance with these laws.

In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Our management believes that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our results of operations, financial position or expected cash flows.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may operate in areas that are currently designated as a habitat for endangered or threatened species or where the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened may occur in which event such one or more developments could cause us to incur additional costs, to develop habitat conservation plans, to become subject to expansion or operating restrictions, or bans in the affected areas.

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Climate Change. On December 15, 2009, the EPA published its findings 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 adopted regulations under existing provisions of the federal Clean Air Act that, among other things, would restrict emissions of greenhouse gases from motor vehicles as well as established Prevention of Significant Deterioration ("PSD") and Title V permitting reviews for certain large stationary sources that are potential sources of greenhouse gas emissions. Facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" standards for greenhouse gases, which are developed on a case-by-case basis. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce or sequester emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our services.

In addition, the EPA has 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, including onshore oil and natural gas production, processing, transmission, storage and distribution facilities. We are monitoring greenhouse gas emissions from certain of our operations in accordance with the greenhouse gas emissions reporting rule and believe that our monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

Various pieces of legislation to reduce emissions of, or to create cap and trade programs for, greenhouse gases have been proposed by the U.S. Congress over the past several years, but no proposal has yet passed. Numerous 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. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for our transportation, storage and processing services by reducing demand for oil, natural gas and NGLs.

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 NGLs and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market 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 products 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.

Employee Health and Safety. We are subject to the requirements of the federal OSHA and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in 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, recordkeeping requirements, and monitoring of occupational exposure to regulated substances.

Employees

As of January 31, 2014, we employed 12,450 persons, 1,466 of which are represented by labor unions. We believe that our relations with our employees are satisfactory.

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 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. Panhandle and Sunoco Logistics file Annual Reports on Form 10-K that include risk factors that can be reviewed for further information. The risk factors set forth below, and those included in Panhandle's and Sunoco Logistics' Annual Report on Form 10-K, 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, crude oil and refined products 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 services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the amount of cash distributions we receive with respect to the Regency, Sunoco Logistics and AmeriGas common units that we or our subsidiaries own;
- the weather in our operating areas;
- the level of competition from other midstream, transportation and storage and retail marketing companies and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level and results 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 revolving credit facility;
- our ability to access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount 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 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 ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding Common Unit may be diminished; and
- the market price of the Common Units or partnership securities may decline.

Sunoco Logistics may issue additional common units, which may increase the risk that Sunoco Logistics will not have sufficient available cash to maintain or increase its per unit distribution level.
Sunoco Logistics' partnership agreement allows it to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by Sunoco Logistics will have the following effects:
- Unitholders' current proportionate ownership interest in Sunoco Logistics, as applicable, will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of Sunoco Logistics common units may decline.

The payment of distributions on any additional units issued by Sunoco Logistics may increase the risk that Sunoco Logistics may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.
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, 2013, ETE owned 49.6 million ETP Common Units. 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 2012, we filed a registration statement to register the sale of 12 million 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.
Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.
Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.
Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.
In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

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

As of December 31, 2013, we had approximately $17.09 billion of consolidated debt, excluding the debt of our joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our and our subsidiaries' cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;
- covenants contained in our and our subsidiaries' existing debt agreements require us and them, as applicable, to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our and our subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership, corporate or limited liability company purposes, as applicable, 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 by us or our subsidiaries to comply with the various restrictive covenants of our respective debt agreements could negatively impact our ability to incur additional debt, including our ability to utilize the available capacity under our revolving credit facility, and our ability to pay our distributions.

Capital 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 and improvements or repairs to existing facilities that 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.

A significant increase in our indebtedness that is proportionately greater than our issuances of equity could negatively impact our and our subsidiaries' credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Increases in interest rates could 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. Approximately $907 million of our consolidated debt as of December 31, 2013 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.

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.

Unitholders have limited voting rights and are not entitled to elect the General Partner or its directors. In addition, even if Unitholders are dissatisfied, they cannot easily remove the General Partner.

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 contractually-limited fiduciary duty 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 may be unable 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, 2013, ETE and its affiliates held approximately 14.8% of our outstanding Common Units, with an additional approximate 1% of our outstanding units held by our officers and directors.

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 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, including Sunoco Logistics. 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 affect our ability to meet our obligations, including any obligations under our debt agreements, and to make distributions to our partners.

A reduction in Sunoco Logistics' distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Through our ownership of equity interests in Sunoco Partners, the holder of the incentive distribution rights in Sunoco Logistics, we are entitled to receive our pro rata share of specified percentages of total cash distributions made by Sunoco Logistics as it reaches established target cash distribution levels as specified in the Sunoco Logistics partnership agreement. We currently receive our pro rata share of cash distributions from Sunoco Logistics based on the highest incremental percentage, 48%, to which Sunoco Partners is entitled pursuant to its incentive distribution rights in Sunoco Logistics. A decrease in the amount of distributions by Sunoco Logistics to less than $0.5275 per common unit per quarter would reduce Sunoco Partners' percentage of the incremental cash distributions above $0.1917 per common unit per quarter from 48% to 35%. As a result, any such reduction in quarterly cash distributions from Sunoco Logistics would have the effect of disproportionately reducing the amount of all distributions that we receive from Sunoco Logistics based on our ownership interest in the incentive distribution rights in Sunoco Logistics as compared to cash distributions we receive from Sunoco Logistics on our General Partner interest in Sunoco Logistics and our Sunoco Logistics common units.

Sunoco Logistics is not prohibited from competing with us.

Neither our partnership agreement nor the partnership agreements of Sunoco Logistics prohibits Sunoco Logistics from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Sunoco Logistics may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

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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 pay distributions to our Unitholders and to service our debt 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 funds from our subsidiaries we may not be able to pay distributions to our Unitholders or to pay interest or principal on our debt when due.

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

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our Available Cash (as defined in our partnership agreement) 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.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions;
- declining market prices for natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

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Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

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 duties owed by our General Partner, and our officers and directors, to the limited partners. Our partnership agreement:

- eliminates all standards of care and duties other than those set forth in our partnership agreement, including fiduciary duties, to the fullest extent permitted by law;
- 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;
- provides that our General Partner may consult with consultants and advisors and, subject to certain restrictions, is conclusively deemed to have acted in good faith when it acts in reliance on the opinion of such consultants and advisors; 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 contractually-limited fiduciary duties 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.
- 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's general partner currently serve as directors of LE GP, LLC, the general partner of ETE.

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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 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.

Income from our midstream, transportation, terminalling and storage operations is exposed to risks due to fluctuations in the demand for and price of natural gas, NGLs and oil that are beyond our control.

The prices for natural gas, NGLs and oil (including refined petroleum products) reflect market demand that fluctuates with changes in global and U.S. economic conditions and other factors, including:

- the level of domestic natural gas, NGL, and oil production;
- the level of natural gas, NGL, and oil imports and exports, including liquefied natural gas;
- actions taken by natural gas and oil producing nations;
- instability or other events affecting natural gas and oil producing nations;
- the impact of weather and other events of nature on the demand for natural gas, NGLs and oil;
- the availability of storage, terminal and transportation systems, and refining, processing and treating facilities;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the cost of capital needed to maintain or increase production levels and to construct and expand facilities
- the impact of energy conservation and fuel efficiency efforts; and
- the extent of governmental regulation, taxation, fees and duties.

In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue.

Any loss of business from existing customers or our inability to attract new customers due to a decline in demand for natural gas, NGLs, or oil could have a material adverse effect on our revenues and results of operations. In addition, significant price fluctuations for natural gas, NGL and oil commodities could materially affect our profitability.

We are affected by competition from other midstream, transportation, terminalling and storage and retail marketing companies.

We experience competition in all of our business segments. With respect to our midstream operations, we compete for both natural gas supplies and customers for our services. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas.

Our natural gas and NGL transportation pipelines and storage facilities compete with other interstate and intrastate pipeline companies and storage providers 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 and NGLs also competes with other forms of energy, including electricity, coal, fuel oils and renewable or alternative energy. Competition among fuels and energy supplies is primarily based on price; however, non-price factors, including governmental regulation, environmental impacts, efficiency, ease of use and handling, and the availability of subsidies and tax benefits also affects competitive outcomes.

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In markets served by our NGL pipelines, we compete with other pipeline companies and barge, rail and truck fleet operations. We also face competition with other storage and fractionation facilities based on fees charged and the ability to receive, distribute and/or fractionate the customer's products.
Our crude oil and refined petroleum products pipelines face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in the areas we serve. Further, our crude and refined product terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.
We also face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations operated by fully integrated major oil companies and other well-recognized national or regional retail outlets, often selling gasoline or merchandise at aggressively competitive prices. The actions of our retail marketing competitors, including the impact of imports, could lead to lower prices or reduced margins for the products we sell, which could have an adverse effect on our business or results of operations.
We may be unable to retain or replace existing midstream, transportation, terminalling and storage customers or volumes due to declining demand or increased competition in oil, natural gas and NGL markets, which would reduce our revenues and limit our future profitability.
The retention or replacement of existing customers and the volume of services that we provide at rates sufficient to maintain or increase current revenues and cash flows depends on a number of factors beyond our control, including the price of and demand for oil, natural gas, and NGLs in the markets we serve and competition from other service providers.
A significant portion of our sales of natural gas are to industrial customers and utilities. As a consequence of the volatility of natural gas prices and increased competition in the industry and other factors, industrial customers, utilities and other gas customers are increasingly reluctant to enter into long-term purchase contracts. Many customers purchase natural gas from more than one supplier and have the ability to change suppliers at any time. Some of these customers 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 natural gas sales markets primarily on the basis of price.
We also receive a substantial portion of our revenues by providing natural gas gathering, processing, treating, transportation and storage services. While a substantial portion of our services are sold under long-term contracts for reserved service, we also provide service on an unreserved or short-term basis. Demand for our services may be substantially reduced due to changing market prices. Declining prices may result in lower rates of natural gas production resulting in less use of services, while rising prices may diminish consumer demand and also limit the use of services. In addition, our competitors may attract our customers' business. If demand declines or competition increases, we may not be able to sustain existing levels of unreserved service or renew or extend long-term contracts as they expire or we may reduce our rates to meet competitive pressures.
Revenue from our NGL transportation systems and refined products storage is also exposed to risks due to fluctuations in demand for transportation and storage service as a result of unfavorable commodity prices, competition from nearby pipelines, and other factors. 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. Reduction in demand for natural gas or NGLs due to unfavorable prices or other factors, however, may result lower rates of production under dedicated contracts and lower demand for our services. In addition, our refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, 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.
The volume of crude oil and refined products transported through our oil pipelines and terminal facilities depends on the availability of attractively priced crude oil and refined products in the areas serviced by our assets. A period of sustained price reductions for crude oil or refined products could lead to a decline in drilling activity, production and refining of crude oil, or import levels in these areas. A period of sustained increases in the price of crude oil or refined products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined

products in these areas. In either case, the volumes of crude oil or refined products transported in our oil pipelines and terminal facilities could decline.

The loss of existing customers by our midstream, transportation, terminalling and storage facilities or a reduction in the volume of the services our customers purchase from us, or our inability to attract new customers and service volumes would negatively affect our revenues, be detrimental to our growth, and adversely affect our results of operations.

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Our midstream facilities and transportation pipelines are attached to basins with naturally declining production, which we may not be able to replace with new sources of supply.

In order to maintain or increase throughput levels on our gathering systems 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.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. Our gas transportation pipelines are also dependent upon natural gas production in areas served by our gathering systems or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. 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. 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. In addition, we have no control over producers or their production and contracting decisions.

While a substantial portion of our services are provided under long-term contracts for reserved service, we also provide service on an unreserved basis. The reserves available through the supply basins connected to our gathering, processing, treating, transportation and storage facilities may decline and may not be replaced by other sources of supply. A decrease in development or production activity could cause a decrease in the volume of unreserved services we provide and a decrease in the number and volume of our contracts for reserved transportation service over the long run, which in each case would adversely affect our revenues and results of operations.

If we are unable to replace any significant volume declines with additional volumes from other sources, our results of operations and cash flows could be materially and adversely affected.

We are entirely dependent upon third parties for the supply of refined products such as gasoline and diesel for our retail marketing business.

We are required to purchase refined products from third party sources, including the joint venture that acquired Sunoco’s Philadelphia refinery. We may also need to contract for new ships, barges, pipelines or terminals which we have not historically used to transport these products to our markets. The inability to acquire refined products and any required transportation services at favorable prices may adversely affect our business and results of operations.

The profitability of certain activities in our natural gas gathering, processing, 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.

For a portion of the natural gas gathered on our systems, 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.

We also 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 revenues and results of operations.

Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations 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 gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.

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When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. 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.

We also receive fees and retain gas in kind from our natural gas transportation and storage customers. Our fuel retention fees and the value of gas that we retain in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease our fuel retention fees and the value of retained gas.

In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana 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 use of derivative financial instruments could result in material financial losses by us.

From time to time, we have sought to reduce our exposure to fluctuations in 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 forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions that are effective economically (whether to mitigate our exposure to fluctuations in commodity prices, or to balance our exposure to fixed and variable interest rates), these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. It is also not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

In addition, even though monitored by management, our derivatives activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to our physical or financial positions or hedging policies and procedures are not followed.

Our natural gas and NGL revenues depend on our customers’ ability to use our pipelines and third-party pipelines over which we have no control.

Our natural gas transportation, storage and NGL businesses depend, in part, on our customers’ ability to obtain access to pipelines to deliver gas to us and receive gas from us. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on our pipelines or third party pipelines due to testing, line repair, reduced operating pressures, or other causes or adverse change in 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 pipelines and facilities and a corresponding material adverse effect on our transportation and storage revenues. In addition, the rates charged by 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.

Shippers using our oil pipelines and terminals are also dependent upon our pipelines and connections to third-party pipelines to receive and deliver crude oil and refined products. Any interruptions or reduction in the capabilities of these pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volume over interconnecting oil pipelines, the allocations of pipeline capacity to our existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in its pipelines or through our terminals. Allocation reductions of this nature are not infrequent and are beyond our control. Any such interruptions or allocation reductions that, individually or in the aggregate, are material or continue for a sustained period of time could have a material adverse effect on our results of operations, financial position, or cash flows.

The inability to continue to access lands owned by third parties could adversely affect our ability to operate and our financial results.

Our ability to operate our pipeline systems on certain lands owned by third parties, will depend on our success in maintaining existing rights-of-way and obtaining new rights-of-way on those lands. We are parties to rights-of-way agreements, permits and licenses authorizing land use with numerous parties, including, private land owners, governmental entities, Native American tribes, rail carriers, public utilities and others. Our ability to secure extensions of existing agreements, permits and licenses is essential to our continuing business operations, and securing additional rights-of-way will be critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to maintain access to existing rights-of-way upon the expiration of the current grants, that all of the rights-of-way will be obtained in a timely fashion or that we will acquire new rights-of-way as needed.

Further, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent down rights or negotiate private agreements cases, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

In addition, we do not own all of the land on which our oil terminal facilities and our retail service stations are located. We have rental agreements for approximately 30% of the company- or dealer-operated retail service stations where we currently control the real estate and we have rental agreements for certain logistics facilities. As such, we are subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. We are also subject to the risk that such agreements may not be renewed.

Additionally, certain facilities and equipment (or parts thereof) used by us are leased from third parties for specific periods. Our inability to renew leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

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 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 strategy, we may, from time to time, engage 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 acquisition efforts will be successful or that any 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, 2013, our consolidated balance sheet reflected $4.73 billion of goodwill and $1.57 billion 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.

During the fourth quarter of 2013, we recorded a goodwill impairment charge of $689 million on our Trunkline LNG reporting unit. See Note 2 to our consolidated financial statements for additional information.

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.

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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 economic, financial and other relevant information that we will consider.

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

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 obtain necessary governmental approvals and contracts with qualified contractors and vendors on acceptable terms;
- we are unable to raise financing for our identified pipeline construction opportunities; or
- we are unable to secure sufficient 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 related 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 new pipelines and related facilities (or the improvement and repair of existing facilities) involves numerous regulatory, environmental, political and legal uncertainties beyond our control and requires 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 oil and natural gas exploration and development drilling activity and the demand for pipeline

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transportation in the areas proposed to be serviced by the project as well as our ability to obtain commitments from producers in the area to utilize the newly constructed pipelines. In this regard, we may construct facilities to capture anticipated future growth in oil or 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 and the loss of any of these key producers could adversely affect our financial results.

For the year ended December 31, 2013, EnerVest Operating, LLC (“EnerVest”), Anadarko E&P Onshore, LLC (“Anadarko”), affiliates of Halcon Operating, Inc. and SEI Energy, LLC supplied us with approximately 60% of the Southeast Texas System’s natural gas supply. For the year ended December 31, 2013, EOG Resources, Inc., affiliates of Chesapeake Energy Corporation, XTO and EnerVest supplied us with approximately 90% of the North Texas System’s natural gas supply. For the year ended December 31, 2013, Rosetta Resources Operating, LP, SWEPI LP (“Shell”), Anadarko and Petrohawk supplied us with approximately 62% of the Rich Eagle Ford Mainline 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.

Our intrastate transportation and storage and interstate transportation and storage operations depend on key customers to transport natural gas through our pipelines and the pipelines of our joint ventures.

We have several nine- and ten-year fee-based transportation contracts with XTO that terminate through 2017, 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 also extended two natural gas storage contracts 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 will terminate in 2015.

During 2013, EDF Inc., Motiva Enterprises LLC, XTO, and Chesapeake Energy Marketing, Inc. collectively accounted for approximately 29% of our intrastate transportation and storage revenues.

With respect to our interstate transportation and storage operations we have an agreement with Chesapeake Energy Marketing, Inc. that provides for a 15-year commitment for firm transportation capacity on the Tiger pipeline 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. Additionally, Panhandle has long-term transportation contracts with BG LNG Services and ProLiance, which accounted for 43% of Panhandle’s 2013 revenue.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP 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, while Citrus has 10 and 14 year agreements with its top two customers, respectively, which accounted for 59% of its 2013 revenue.

During 2013, BG Energy Holdings, Chesapeake Energy Marketing, Inc., Ameren Corporation, EnCana Marketing (USA), Inc., and Petrohawk Energy Corporation collectively accounted for 44% of our interstate transportation and storage revenues.

The failure of the major shippers on our and our joint ventures’ intrastate and interstate transportation and storage pipelines to fulfill their contractual obligations could have a material adverse effect on our cash flow and results of operations if we or our joint ventures were unable to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

Our interstate pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services, which may prevent us from fully recovering our costs.

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.
We are required to file tariff rates (also known as recourse rates) with the FERC that shippers may pay for interstate natural gas transportation services. We may also agree to discount these rates on a not unduly discriminatory basis or negotiate rates with shippers who elect not to pay the recourse rates. The FERC must approve or accept all rate filings for us to be allowed to charge such rates.

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The FERC may review existing tariffs rates on its own initiative or upon receipt of a complaint filed by a third party. The FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates we are permitted to charge may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

The costs of our interstate pipeline operations may increase and we may not be able to recover all of those costs due to FERC regulation of our rates. If we propose to change our tariff rates, our proposed rates may be challenged by the FERC or third parties, and the FERC may deny, modify or limit our proposed changes if we are unable to persuade the FERC that changes would result in just and reasonable rates that are not unduly discriminatory. We also may be limited by the terms of rate case settlement agreements or negotiated rate agreements with individual customers from seeking future rate increases, or we may be constrained by competitive factors from charging our tariff rates.

To the extent our costs increase in an amount greater than our revenues increase, or there is a lag between our cost increases and our ability to file for, and obtain rate increases, our operating results would be negatively affected. Even if a rate increase is permitted by the FERC to become effective, the rate increase may not be adequate. We cannot guarantee that our interstate pipelines will be able to recover all of our costs through existing or future rates.

In July 2010, in response to an intervention and protest filed by BGLS regarding its rates with Trunkline LNG applicable to certain LNG expansions, the FERC determined that there was no reason at that time to expend the FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided to the FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. The current fixed rates expire at the end of 2015 and revert to tariff rate for these LNG expansions as well as the base LNG facilities for which rates were set in 2002.

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 effectiveness of the FERC's policy and the application of that policy remain subject to future challenges, refinement or change by the FERC or the courts.

Our interstate pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect our business and results of 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 or must 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. In addition, we cannot guarantee that the FERC will authorize tariff changes and other activities we might propose to do so in a timely manner and free from potentially burdensome conditions. Future changes to laws, regulations, policies and interpretations thereof in these and other applicable areas may impair our access to capital markets or 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.

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Rate regulation or market conditions may not allow us to recover the full amount of increases in the costs of our crude oil and refined products pipeline operations.

Transportation provided on our common carrier interstate crude oil and refined products pipelines is subject to rate regulation by the FERC, which requires that tariff rates for transportation on these oil pipelines be just and reasonable and not unduly discriminatory. If we propose new or changed rates, the FERC or interested persons may challenge those rates and the FERC is authorized to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the proposed rate is unjust or unreasonable, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC's ratemaking methodologies may limit our ability to set rates based on our costs or may delay the use of rates that reflect increased costs. In addition, if the FERC's indexing methodology changes, the new methodology could materially and adversely affect our financial condition, results of operations or cash flows.

Under the Energy Policy Act adopted in 1992, certain interstate pipeline rates were deemed just and reasonable or "grandfathered." Revenues are derived from such grandfathered rates on most of our FERC-regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If the FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline's costs. In such event, the FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

If the FERC's petroleum pipeline ratemaking methodologies procedures changes, the new methodology or procedures could adversely affect our business and results of operations.

State regulatory measures could adversely affect the business and operations of our midstream and intrastate pipeline and storage 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 service for the interstate services we provide in our intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. Our HPL System, East Texas pipeline, Oasis pipeline and ET Fuel System provide such services. Under Section 311, rates charged for transportation and storage must be fair and equitable. 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 costs of service, our cash flow would be negatively affected.

Our midstream and intrastate gas and oil transportation pipelines and our intrastate gas storage operations are subject to state regulation. All of the states in which we operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted some form of complaint-based regulation, which allow producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to the fairness of rates and terms of access. The states in which we operate have ratable take statutes, which generally require gatherers to take, without undue discrimination, 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. Should a complaint be filed in any of these states or should regulation become more active, our business may be adversely affected.

Our intrastate transportation operations located in Texas are also subject to regulation as gas utilities by the TRRC. Texas gas utilities must publish the rates they charge for transportation and storage services in tariffs filed with the TRRC, although such rates are deemed just and reasonable under Texas law unless challenged in a complaint.

We are subject to other forms of state regulation, including requirements to obtain operating permits, reporting requirements, and safety rules (see description of federal and state pipeline safety regulation below). Violations state laws, regulations, orders and permit conditions can result in the modification, cancellation or suspension of a permit, civil penalties and other relief.

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Certain of our assets may become subject to regulation.
The distinction between federally unregulated gathering facilities and FERC-regulated transmission pipelines under the NGA has been the subject of extensive litigation and may be determined by the FERC on a case-by-case basis, although the FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of our gathering facilities could change based on future determinations by the FERC, the courts or Congress. If our gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers.
Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star's NGL Pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGLs transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Lone Star's NGL pipeline also commenced the interstate transportation of NGLs in 2013, which is subject to FERC's jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. Both intrastate and interstate NGL transportation services must be provided in a manner that is just, reasonable, and non-discriminatory. The tariff rates established for interstate services were based on a negotiated agreement; however if FERC's rate making methodologies were imposed, they 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.
We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.
Pursuant to authority under the NGPSA and HLPSA, as amended by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources, and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. Any changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, changes to regulations governing the safety of gas transmission pipelines and gathering lines are being considered by PHMSA, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed.
Our business involves hazardous substances and may be adversely affected by environmental regulation.
Our operations are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment, worker health and safety and protection of 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. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or released, even under circumstances where the substances, hydrocarbons or wastes have been released by a predecessor operator. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by noise, odor or the release of hazardous substances, hydrocarbons or wastes into the environment.

We may incur substantial environmental costs and liabilities because of the underlying risk inherent to our operations. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation costs, liabilities for natural resource damages that could substantially increase our costs for site remediation projects. Accordingly, we cannot assure you that our current reserves are adequate to cover all future liabilities, even for currently known contamination.

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, in 2008 the EPA 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 NOx emission reduction requirements that affect our compressor units in ozone non-attainment areas at reasonable cost, but there is no assurance that we will not incur material costs in the future to meet the new ozone standard.

Product liability claims and litigation could adversely affect our business and results of operations.

Product liability is a significant commercial risk. Substantial damage awards have been made in certain jurisdictions against manufacturers and resellers based upon claims for injuries caused by the use of or exposure to various products. There can be no assurance that product liability claims against us would not have a material adverse effect on our business or results of operations.

Along with other refiners, manufacturers and sellers of gasoline, Sunoco is a defendant in numerous lawsuits that allege MTBE contamination in groundwater. Plaintiffs, who include water purveyors and municipalities responsible for supplying drinking water and private well owners, are seeking compensatory damages (and in some cases injunctive relief, punitive damages and attorneys' fees) for claims relating to the alleged manufacture and distribution of a defective product (MTBE-containing gasoline) that contaminates groundwater, and general allegations of product liability, nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. There has been insufficient information developed about the plaintiffs' legal theories or the facts that would be relevant to an analysis of the ultimate liability to Sunoco. These allegations or other product liability claims against Sunoco could have a material adverse effect on our business or results of operations.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the services we provide.

In December 2009, the EPA published its findings 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 adopted rules under the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources, which reviews could require securing PSD permits at covered facilities emitting greenhouse gases and meeting "best available control technology" standards for those greenhouse gas emissions. In addition, the EPA has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis, which include certain of our operations. While Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of greenhouse gases or otherwise restricts emissions of greenhouse gases from our equipment and operations could require us to incur significant added costs to reduce emissions of greenhouse gases or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide.

The adoption of the Dodd-Frank Act 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, resulting in our operations becoming more volatile and our cash flows less predictable.

Congress has adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), a comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The legislation was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. While certain regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

The Dodd-Frank Act expanded the types of entities that are required to register with the CFTC and the SEC as a result of their activities in the derivatives markets or otherwise become specifically qualified to enter into derivatives contracts. We will be required to assess our activities in the derivatives markets, and to monitor such activities on an ongoing basis, to ascertain and to identify any potential change in our regulatory status.

Reporting and recordkeeping requirements also could significantly increase operating costs and expose us to penalties for non-compliance. Certain CFTC recordkeeping requirements became effective on October 14, 2010, and additional recordkeeping requirements will be phased in through April 2013. Beginning on December 31, 2012, certain CFTC reporting rules became effective, and additional reporting requirements will be phased in through April 2013. These additional recordkeeping and reporting requirements may require additional compliance resources. Added public transparency as a result of the reporting rules may also have a negative effect on market liquidity which could also negatively impact commodity prices and our ability to hedge.

The CFTC has also issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC’s position limits rules were to become effective on October 12, 2012, but a United States District Court vacated and remanded the position limits rules to the CFTC. The CFTC has appealed that ruling and it is uncertain at this time whether, when, and to what extent the CFTC’s position limits rules will become effective.

The new regulations may also require us to comply with certain margin requirements for our over-the counter derivative contracts with certain CFTC- or SEC-registered entities that could require us to enter into credit support documentation and/or post significant amounts of cash collateral, which could adversely affect our liquidity and ability to use derivatives to hedge our commercial price risk; however, the proposed margin rules are not yet final and therefore 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 also requires that certain derivative instruments be centrally cleared and executed through an exchange or other approved trading platform. Mandatory exchange trading and clearing requirements could result in increased costs in the form of additional margin requirements imposed by clearing organizations. On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which was March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although there may be an exception to the mandatory exchange trading and clearing requirement that applies to our trading activities, we must obtain approval from the board of directors of our General Partner and make certain filings in order to rely on this exception. In addition, mandatory clearing requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

Rules promulgated under the Dodd-Frank Act further defined forwards as well as instances where forwards may become swaps. Because the CFTC rules, interpretations, no-action letters, and case law are still developing, it is possible that some arrangements that previously qualified as forwards or energy service contracts may fall in the regulatory category of swaps or options. In addition, the CFTC’s rules applicable to trade options may further impose burdens on our ability to conduct our traditional hedging operations and could become subject to CFTC investigations in the future.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), 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 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. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

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.

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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.

The United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such terrorist attack on our facilities or pipelines, those of our customers, or in some cases, those of other pipelines could have a material adverse effect on our business, financial condition and results of operations.

Cybersecurity breaches and other disruptions could compromise our information and expose us to liability, which would cause our business and reputation to suffer.

In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personal identification information of our employees, in our data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disruption of our operations, damage to our reputation, and cause a loss of confidence in our products and services, which could adversely affect our business.

We have an 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.

As of December 31, 2013, we owned approximately 22.1 million AmeriGas common units and, as a result of a sale of approximately 9.2 million AmeriGas common units in January 2014, we owned 12.9 million AmeriGas common units as of January 31, 2014. 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;

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- 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.

More stringent regulatory initiatives in the U.S. Gulf of Mexico in the aftermath of the Macondo well oil spill may result in increased costs and delays in offshore oil and natural gas exploration and production operations, which costs and delays could significantly decrease the volume of our business and have a material adverse effect on our results of operations, financial position and liquidity.

In response to an April 2010 fire and explosion aboard the Deepwater Horizon drilling rig and resulting oil spill from the Macondo well operated by a third party in ultra-deep water in the U.S. Gulf of Mexico, federal authorities have pursued a series of regulatory initiatives to address the direct impact of that incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through 2013, the federal government, acting through the U.S. Department of the Interior, or DOI, and its implementing agencies that have since evolved into the present day Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement has issued various rules, Notices to Lessees and Operators and temporary drilling moratoria that impose or result in added environmental and safety measures upon exploration, development and production operators in the U.S. Gulf of Mexico. These regulatory initiatives may serve to effectively slow down the pace of drilling and production operations in the U.S. Gulf of Mexico due to adjustments in operating procedures and certification practices, increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits and thus result in increased costs for affected operators, some of whom are our customers. The increased regulations and cost of drilling operations could result in decreased drilling activity in the areas serviced by us. Furthermore, business decisions by operators not to drill in the areas serviced by us in the future owing to the more rigorous regulatory environmental or increased costs of operating also could result in a reduction in the future development and production of natural gas reserves in the vicinity of our facilities, which could adversely affect our business, financial condition results of operations and cash flows. Also, if similar events were to occur in the future in the U.S. Gulf of Mexico in areas where we conduct operations, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development, which developments could have a material adverse effect on our volume of business as well as our financial position, results of operations and liquidity.

Our business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store and transport.

The petroleum products that we store and transport through Sunoco Logistics' operations are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce our throughput volume, require us to incur additional handling costs or require the expenditure of significant capital. In addition, different product specifications for different markets impact the fungibility of products transported and stored in our pipeline systems and terminal facilities and could require the construction of additional storage to segregate products with different specifications. We may be unable to recover these costs through increased revenues.

In addition, our butane blending services are reliant upon gasoline vapor pressure specifications. Significant changes in such specifications could reduce butane blending opportunities, which would affect our ability to market our butane blending services licenses.

Our business could be affected adversely by union disputes and strikes or work stoppages by unionized employees.

As of December 31, 2013, approximately 12% of our workforce is covered by a number of collective bargaining agreements with various terms and dates of expirations. There can be no assurances that we will not experience a work stoppage in the future as

a result of labor disagreements. Any work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on our business, financial position, results of operations or cash flows.
Governmental regulations and policies, particularly in the areas of taxation, energy and the environment, have a significant impact on our retail marketing business.
Federally mandated standards for use of renewable biofuels, such as ethanol and biodiesel in the production of refined products, are transforming traditional gasoline and diesel markets in North America. These regulatory mandates present production and logistical challenges for both the petroleum refining and ethanol industries, and may require us to incur additional capital expenditures or expenses particularly in our retail marketing business. We may have to enter into arrangements with other parties to meet our obligations to use advanced biofuels, with potentially uncertain supplies of these new fuels. If we are unable to obtain or maintain sufficient quantities of ethanol to support our blending needs, our sale of ethanol blended gasoline could be interrupted or suspended which could result in lower profits. There also will be compliance costs related to these regulations. We may experience a decrease in demand for refined petroleum products due to new federal requirements for increased fleet mileage per gallon or due to replacement of refined petroleum products by renewable fuels. In addition, tax incentives and other subsidies making renewable fuels more competitive with refined petroleum products may reduce refined petroleum product margins and the ability of refined petroleum products to compete with renewable fuels. A structural expansion of production capacity for such renewable biofuels could lead to significant increases in the overall production, and available supply, of gasoline and diesel in markets that we supply. In addition, a significant shift by consumers to more fuel-efficient vehicles or alternative fuel vehicles (such as ethanol or wider adoption of gas/electric hybrid vehicles), or an increase in vehicle fuel economy, whether as a result of technological advances by manufacturers, legislation mandating or encouraging higher fuel economy or the use of alternative fuel, or otherwise, also could lead to a decrease in demand, and reduced margins, for the refined petroleum products that we market and sell.
It is possible that any, or a combination, of these occurrences could have a material adverse effect on Sunoco's business or results of operations.
We have outsourced various functions related to our retail marketing business to third-party service providers, which decreases our control over the performance of these functions. Disruptions or delays of our third-party outsourcing partners could result in increased costs, or may adversely affect service levels. Fraudulent activity or misuse of proprietary data involving our outsourcing partners could expose us to additional liability.
Sunoco has previously outsourced various functions related to our retail marketing business to third parties and expects to continue this practice with other functions in the future.
While outsourcing arrangements may lower our cost of operations, they also reduce our direct control over the services rendered. It is uncertain what effect such diminished control will have on the quality or quantity of products delivered or services rendered, on our ability to quickly respond to changing market conditions, or on our ability to ensure compliance with all applicable domestic and foreign laws and regulations. We believe that we conduct appropriate due diligence before entering into agreements with our outsourcing partners. We rely on our outsourcing partners to provide services on a timely and effective basis. Although we continuously monitor the performance of these third parties and maintain contingency plans in case they are unable to perform as agreed, we do not ultimately control the performance of our outsourcing partners. Much of our outsourcing takes place in developing countries and, as a result, may be subject to geopolitical uncertainty. The failure of one or more of our third-party outsourcing partners to provide the expected services on a timely basis at the prices we expect, or as required by contract, due to events such as regional economic, business, environmental or political events, information technology system failures, or military actions, could result in significant disruptions and costs to our operations, which could materially adversely affect our business, financial condition, operating results and cash flow.
Our failure to generate significant cost savings from these outsourcing initiatives could adversely affect our profitability and weaken Sunoco's competitive position. Additionally, if the implementation of our outsourcing initiatives is disruptive to our retail marketing business, we could experience transaction errors, processing inefficiencies, and the loss of sales and customers, which could cause our business and results of operations to suffer.
As a result of these outsourcing initiatives, more third parties are involved in processing our retail marketing information and data. Breaches of security measures or the accidental loss, inadvertent disclosure or unapproved

dissemination of proprietary information or sensitive or confidential data about our retail marketing business or our clients, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose us to a risk of loss or misuse of this information, result in litigation and potential liability for us, lead to reputational damage to the Sunoco brand, increase our compliance costs, or otherwise harm our business.

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Our operations could be disrupted if our information systems fail, causing increased expenses and loss of sales.
Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including our enterprise resource planning tools. We process a large number of transactions on a daily basis and rely upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, our operations and financial results could be affected adversely. Our systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. We have a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Our business interruption insurance may not compensate us adequately for losses that may occur.
Security breaches and other disruptions could compromise our information and operations, and expose us to liability, which would cause our business and reputation to suffer.
In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personally identifiable information of our employees, in our data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of our operations, damage to our reputation, and loss of confidence in our products and services, which could adversely affect our business.
Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-today operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations.
The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of providing health care benefits for employees.
Certain of our subsidiaries provide pension plan and other postretirement healthcare benefits to certain of their employees. The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension and other postretirement fund values, changing demographics and fluctuating actuarial assumptions that may have a material adverse effect on the Partnership’s future consolidated financial results. In addition, the passage of the Health Care Reform Act of 2010 could significantly increase the cost of health care benefits for our employees. While certain of the costs incurred in providing such pension and other postretirement healthcare benefits are recovered through the rates charged by the Partnership’s regulated businesses, the Partnership’s subsidiaries may not recover all of the costs and those rates are generally not immediately responsive to current market conditions or funding requirements. Additionally, if the current cost recovery mechanisms are changed or eliminated, the impact of these benefits on operating results could significantly increase.
Mergers among Sunoco Logistics’ customers and competitors could result in lower volumes being shipped on its pipelines or products stored in or distributed through its terminals, or reduced crude oil marketing margins or volumes.
Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing systems instead of Sunoco Logistics’ systems in those markets where the systems compete. As a result, Sunoco Logistics could lose some or all of the volumes and associated revenues from these customers and could experience difficulty in replacing those lost volumes and revenues, which could materially and adversely affect our results of operations, financial position, or cash flows.
A portion of Sunoco Logistics’ general and administrative services have been outsourced to third-party service providers. Fraudulent activity or misuse of proprietary data involving its outsourcing partners could expose us to

additional liability.

Sunoco Logistics utilizes both affiliate entities and third parties in the processing of its information and data. Breaches of its security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about Sunoco Logistics or its customers, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose Sunoco Logistics to a risk of loss or misuse of this information, result in litigation and potential liability for Sunoco Logistics, lead to reputational damage, increase compliance costs, or otherwise harm its business.

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A material decrease in demand or distribution of crude oil available for transport through Sunoco Logistics' pipelines or terminal facilities could materially and adversely affect our results of operations, financial position, or cash flows.
The volume of crude oil transported through Sunoco Logistics' crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by its assets. A period of sustained crude oil price declines could lead to a decline in drilling activity, production and import levels in these areas. Similarly, a period of sustained increases in the price of crude oil supplied from any of these areas, as compared to alternative sources of crude oil available to Sunoco Logistics' customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in Sunoco Logistics' crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all. If Sunoco Logistics is unable to replace any significant volume declines with additional volumes from other sources, our results of operations, financial position, or cash flows could be materially and adversely affected.
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 Internal Revenue Service ("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, then our cash available for distribution would be substantially reduced.
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, we would be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.
If we were treated as a corporation, 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 at varying rates. 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.
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. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our case available for distribution to our unitholders.
The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.
The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the federal income tax laws and

interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for federal income tax purposes.

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The tax treatment of Sunoco Logistics depends on its status as a partnership for federal income tax purposes, as well as its not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat Sunoco Logistics as a corporation for federal income tax purposes or if it were to 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 its unitholders.

The anticipated after-tax economic benefit of our investment in the common units of Sunoco Logistics depends largely on Sunoco Logistics being treated as a partnership for federal income tax purposes. Sunoco Logistics has not requested, and does not plan to request, a ruling from the IRS on this matter. The IRS may adopt positions that differ from the ones Sunoco Logistics has taken. A successful IRS contest of the federal income tax positions Sunoco Logistics takes may impact adversely the market for its common units, and the costs of any IRS contest will reduce Sunoco Logistics' cash available for distribution to its unitholders. If Sunoco Logistics were to be treated as a corporation for federal income tax purposes, it would pay federal income tax at the corporate tax rate, and likely would pay state income tax at varying rates. Distributions to its unitholders generally would be subject to tax again as corporate distributions. Treatment of Sunoco Logistics as a corporation would result in a material reduction in its anticipated cash flow and after-tax return to its unitholders. Current law may change so as to cause Sunoco Logistics to be treated as a corporation for federal income tax purposes or to otherwise subject it to a material amount of entity-level taxation. 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 states were to impose a tax on Sunoco Logistics, the cash available for distribution to its unitholders would be reduced.

As discussed above, the present federal income tax treatment of publicly traded partnerships, including Sunoco Logistics, or our investment in its common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for Sunoco Logistics to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause Sunoco Logistics to change its business activities, or affect the tax consequences of our investment in Sunoco Logistics' common units. Any such changes could negatively impact the value of our investment in Sunoco Logistics' common units.

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.

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 result in a decrease in 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 of depreciation deductions and certain other items. In addition, because the amount realized includes a Unitholder's share of our nonrecourse liabilities, if a Unitholder sells units, the Unitholder may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be "unrelated business taxable income" and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective tax rate applicable to non-U.S. persons, and each non-U.S. person will be required to file United States federal and state income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or non-U.S. person, you should consult your tax advisor before investing in our common units.

We have subsidiaries that will be treated as corporations for federal income tax purposes and subject to corporate-level income taxes.

Even though we (as a partnership for U.S. federal income tax purposes) are not subject to U.S. federal income tax, some of our operations are currently, and our acquisition of Sunoco and the Holdco restructuring resulted in an increase in the proportion of our operations that are conducted through subsidiaries that are organized as corporations for U.S. federal income tax purposes. The taxable income, if any, of subsidiaries that are treated as corporations for U.S. federal income tax purposes, is subject to corporate-level U.S. federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that these corporations have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by these corporate subsidiaries require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by these subsidiaries are fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

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.

Because we cannot match transferors and transferees of Common Units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our Unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to tax returns of our Unitholders. Moreover, because we have subsidiaries that are organized as C corporations for federal income tax purposes which own 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 generally 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 the subject of a securities loan (e.g. a loan 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 there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a Unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the Unitholder may 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 such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect

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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 of their units 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 to have technically terminated as a partnership 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 (and our Unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a Unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such Unitholder’s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes 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. The IRS has recently announced a relief procedure whereby a publicly traded partnership that has technically terminated may be permitted to provide only a single Schedule K-1 to unitholders for the two tax years within the fiscal year in which the termination occurs.

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 many states, most of which 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

A description of our properties is included in “Item 1. Business.” In addition, 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. 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

Sunoco, along with other refiners, manufacturers and sellers of gasoline, is a defendant in lawsuits alleging MTBE contamination of groundwater. The plaintiffs typically include water purveyors and municipalities responsible for supplying drinking water and governmental authorities. The plaintiffs are asserting primarily product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. The plaintiffs in all of the cases are seeking to recover compensatory damages, and in some cases, injunctive relief , punitive damages and attorneys’ fees.

As of December 31, 2013, Sunoco is a defendant in seven cases, one of which was initiated by the State of New Jersey and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Six of these cases are venued in a multidistrict litigation (“MDL”) proceeding in a New York federal court. The most recently filed Puerto Rico action is expected to be transferred to the MDL. The New Jersey and Puerto Rico cases assert natural resource damage claims. In addition, Sunoco has received notice from another state that it intends to file an MTBE lawsuit in the near future asserting natural resource damage claims.

Fact discovery has concluded with respect to an initial set of fewer than 20 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. Insufficient information has been developed about the plaintiffs’ legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership’s consolidated financial position.

In January 2012, Sunoco Logistics experienced a release on its refined products pipeline in Wellington, Ohio. In connection with this release, the PHMSA issued a Corrective Action Order under which Sunoco Logistics is obligated to follow specific requirements in the investigation of the release and the repaid and reactivation of the pipeline. Sunoco Logistics also entered into an Order on Consent with the EPA regarding the environmental remediation of the release site. All requirements of the Order of Consent with the EPA have been fulfilled and the Order has been satisfied and closed. Sunoco Logistics has also received a "No Further Action" approval from the Ohio EPA for all soil and groundwater remediation requirements. Sunoco Logistics has not received any proposed penalties associated with this release and continues to cooperate with both PHMSA and the EPA to complete the investigation of the incident and repair of the pipeline.

In 2012, the EPA issued a proposed consent agreement related to the releases that occurred at Sunoco Logistics' pump station/tank farm in Barbers Hill, Texas and pump station/tank farm located in Cromwell, Oklahoma in 2010 and 2011, respectively. These matters were referred to the U.S. Department of Justice ("DOJ") by the EPA. In November 2012, Sunoco Logistics received an initial assessment of $1.4 million associated with these releases. Sunoco Logistics is in discussions with the EPA and the DOJ on this matter and hopes to resolve the issue during 2014.

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In September 2013, the Pennsylvania Department of Environmental Protection ("PADEP") issued a Notice of Violation and proposed penalties in excess of $0.1 million based on alleged violations of various safety regulations relating to the November 2008 products release by Sunoco Pipeline L.P., a subsidiary of Sunoco Logistics, in Murrysville, Pennsylvania. Sunoco Logistics is currently in discussions with the PADEP. The timing or outcome of this matter cannot be reasonably determined at this time. However, we do not expect a material impact to the Partnership's results of operations, cash flows or financial position.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed below were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report environmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $0.1 million. For a description of legal proceedings, see Note 10 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 2013			
Fourth Quarter	$57.31	$50.60	$0.92000
Third Quarter	54.85	49.40	0.90500
Second Quarter	53.00	45.16	0.89375
First Quarter	50.71	43.67	0.89375
Fiscal Year 2012			
Fourth Quarter	$45.00	$40.19	$0.89375
Third Quarter	46.00	41.35	0.89375
Second Quarter	51.00	41.15	0.89375
First Quarter	50.12	45.75	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 21, 2014, there were approximately 512,000 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 8.9 million Class E Units outstanding, all of which are currently owned by HHI. The Class E Units generally do not have any voting rights. The 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.

In conjunction with the Sunoco Merger, we amended our partnership agreement to create the Class F Units. The number of Class F Units issued was determined at the closing of the Sunoco Merger and equaled 90.7 million, which included 40 million Class F Units issued in exchange for cash contributed by Sunoco to us immediately prior to or concurrent with the closing of the Sunoco Merger. The Class F Units generally did not have any voting rights. The Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by us and our subsidiaries, other than Holdco, and available for distribution, up to a maximum of $3.75 per Class F Unit per year. In April 2013, all of the outstanding Class F Units were exchanged for Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are held by a subsidiary and therefore are reflected as treasury units in the consolidated financial statements.

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the “Redeemed

Units”) owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the “Class H Units”), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the IDR subsidies previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the Class H Units, ETE and ETP also agreed to certain adjustments to the prior IDR subsidies in order to ensure that the IDR subsidies are fixed amounts for each quarter to which the IDR subsidies are in effect.

As of December 31, 2013, our General Partner owned an approximate 0.7% general partner interest in us and the holders of Common Units, Class E, Class G and Class H Units collectively owned a 99.3% limited partner interest in us.

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.

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 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.

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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 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 enables us, if we choose, to distribute as operating surplus up to $10 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

The terms of our partnership agreement require that we make cash distributions with respect to each calendar quarter within 45 days following the end of each calendar quarter. For any quarter, we are required to make distributions of Available Cash from operating surplus initially to the Class H Unitholders in an amount equal to 50.05% of all distributions to ETP by Sunoco Partners LLC with respect to the incentive distribution rights and general partner interest in Sunoco Logistics, calculated on a cumulative basis beginning October 31, 2013. We are also required to make incremental cash distributions to the Class H Unitholders in the aggregate amount of $329 million, subject to adjustment, over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. We are required to make distributions of any remaining Available Cash from operating surplus for any quarter in the following manner:

- First, 100% to all Common Unitholders, Class E Unitholders, Class G Unitholders and the general partner, in accordance with their percentage interests, until each Common Unit has received $0.25 per unit for such quarter (the “minimum quarterly distribution”);
- Second, 100% to all Common Unitholders, Class E Unitholders, Class G Unitholders and the general partner, in accordance with their respective percentage interests, until each Common Unit has received $0.275 per unit for such quarter (the “first target distribution”);
- Third, (i) to the general partner in accordance with its percentage interest, (ii) 13% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.3175 per unit for such quarter (the “second target distribution”);
- Fourth, (i) to the general partner in accordance with its percentage interest, (ii) 23% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.4125 per unit for such quarter (the “third target distribution”); and
- Fifth, thereafter, (i) to the general partner in accordance with its percentage interest, (ii) 48% to the holder of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs.

The allocation of distributions among the Common, Class E, Class G and Class H Unitholders and the General Partner is based on their respective interests as of the record date for such distributions.

Notwithstanding the foregoing, the distributions on each Class E unit may not exceed $1.41 per year and distributions on each Class G unit may not exceed $3.75 per year. In addition, the distributions to the holders of the incentive distribution rights will not exceed the amount the holders of the incentive distributions rights would otherwise receive if the available cash for distribution were reduced to the extent it constitutes amounts previously distributed with respect to the Class G units.

The incentive distributions described above do not reflect the impact of IDR subsidies previously agreed to by ETE in connection with previous transactions, as described below under “IDR Subsidies.”

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Distributions of Available Cash from Capital Surplus

We are required to make distributions of Available Cash from capital surplus initially to the Class H Unitholders in a manner similar to the distributions of Available Cash from operating surplus, as described above. We will make distributions of any remaining Available Cash from capital surplus 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 7 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

IDR Subsidies

As described above, our partnership agreement requires certain incentive distributions to the holders of the IDRs. As the holder of the IDRs, ETE has previously agreed to incremental distribution relinquishments in connection with our acquisition of Citrus Corp., our and ETE's formation of Holdco and the subsequent contribution of ETE's interest in Holdco to us.

In addition, the incremental distributions on the Class H Units, which are referred to in "Distributions of Available Cash from Operating Surplus" above, were intended to offset a portion of the incremental distribution relinquishments previously granted by ETE to the Partnership. In connection with the issuance of the Class H Units, ETE and the Partnership also agreed to certain adjustments to the incremental distributions on the Class H Units in order to ensure that the net impact of the incremental distribution relinquishments (a portion of which is variable) and the incremental distributions on the Class H Units are fixed amounts for each quarter for which the incremental distribution relinquishments and incremental distributions on the Class H Units are in effect.

In addition to the amounts above, in connection with the Partnership's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of incentive distributions of $50 million, $50 million, $45 million and $35 million for the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

Following is a summary of the net amounts by which these incremental distribution relinquishments and incremental distributions on Class H Units would reduce the total distributions that would potentially be made to ETE in future quarters:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$26.5	$26.5	$26.5	$26.5	$106.0
2015	12.5	12.5	13.0	13.0	51.0
2016	18.0	18.0	18.0	18.0	72.0
2017	12.5	12.5	12.5	12.5	50.0
2018	11.25	11.25	11.25	11.25	45.0

2019	8.75	8.75	8.75	8.75	35.0

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Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The following table discloses purchases of ETP Common Units made by us or on our behalf in the quarter ended December 31, 2013:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Not Purchased as Part of Publicly Announced Plans or Programs [1]	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs
October 2013	—	$—	—	—
November 2013	—	—	—	—
December 2013	379,599	54.28	379,599	—

(1) The units reported in this column represent purchases settled during the quarter ended December 31, 2013 relating to our purchases of units in open-market transactions to meet our obligations under our equity incentive plans for employees, officers and directors.

ITEM 6. SELECTED FINANCIAL DATA

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 millions.

In accordance with GAAP, we have accounted for the Holdco Transaction, whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements for the year ended December 31, 2012 reflected retrospective consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union). In 2013, Southern Union disposed of the assets of MGE and NEG. The results of continuing operations of the distribution operations were reflected as income from discontinued operations.

These changes only impacted interim periods in 2012, and no prior annual amounts have been adjusted for the Holdco Transaction.

In October 2012, we sold ETC Canyon Pipeline, LLC ("Canyon"), and the results of continuing operations of Canyon were reflected as discontinued operations.

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	Years Ended December 31, 2013	2012	2011	2010	2009
Statement of Operations Data:					
Total revenues	$46,339	$15,702	$6,799	$5,843	$5,378
Operating income	1,541	1,394	1,247	1,065	1,134
Income from continuing operations	735	1,757	700	623	797
Basic income (loss) from continuing operations per limited partner unit	(0.23)	4.93	1.12	1.23	2.56
Diluted income (loss) from continuing operations per limited partner unit	(0.23)	4.91	1.12	1.23	2.56
Cash distributions per unit	3.68	3.58	3.58	3.58	3.58
Balance Sheet Data (at period end):					
Total assets	43,702	43,230	15,519	12,150	11,735
Long-term debt, less current maturities	16,451	15,442	7,388	6,405	6,177
Total equity	16,288	17,332	6,350	4,743	4,600
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	343	313	134	99	103
Growth (accrual basis)	2,112	2,736	1,350	1,276	524
Cash (received in) paid for acquisitions	1,737	1,364	1,972	178	(30)

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

(Tabular dollar and unit amounts, except per unit data, are in millions)

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 primary activities and operating subsidiaries 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 we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Refined product and crude oil operations, including the following:
  - refined product and crude oil transportation through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco and MACS.

Recent Developments

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Sale of AmeriGas Common Units

On July 12, 2013, we sold 7.5 million AmeriGas common units for net proceeds of $346 million. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility. In January 2014, we sold 9.2 million AmeriGas common units for net proceeds of $381 million. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility and for general partnership purposes.

Class H Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in

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ETP (the "Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the IDR subsidies previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the Class H Units, ETE and ETP also agreed to certain adjustments to the prior IDR subsidies in order to ensure that the IDR subsidies are fixed amounts for each quarter to which the IDR subsidies are in effect. For a summary of the net IDR subsidy amounts resulting from this transaction, see "Quarterly Distributions of Available Cash" in Note 7.

LNG Export Project

On August 7, 2013, Lake Charles Exports, LLC, an entity owned by BG LNG Services, LLC and Trunkline LNG Holdings, LLC, received an order from the Department of Energy conditionally granting authorization to export up to 15 million metric tonnes per annum of LNG to non-free trade agreement countries from the existing LNG import terminal owned by Trunkline LNG Company, LLC, which is located in Lake Charles, Louisiana. Lake Charles Exports, LLC previously received approval to export LNG from the Lake Charles facility to free trade agreement countries on July 22, 2011. In October 2013, Trunkline and BG Group announced their entry into a project development agreement to jointly develop the LNG export project at the existing Trunkline LNG import terminal.

Sale of Southern Union's Distribution Operations

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

Retail Acquisition

In October 2013, La Grange Acquisition, L.P., an indirect wholly-owned subsidiary of ETP, acquired convenience store operator MACS with a network of approximately 300 company-owned and dealer locations. These operations will be reflected in ETP's retail marketing segment, along with the retail marketing operations owned by Holdco, beginning in the fourth quarter of 2013.

Resumption of Distribution Rate Growth

In the third quarter of 2013, ETP increased its quarterly distribution rate to $0.905 per unit ($3.62 annualized). With respect to the quarter ended December 31, 2013, ETP increased its quarterly distribution rate to $0.92 per unit ($3.68 annualized).

Second Fractionator at Lone Star's Mont Belvieu Facility

In November 2013, we announced that Lone Star has placed in service a second 100,000 barrel-per-day NGL fractionator at its facility in Mont Belvieu, Texas, bringing Lone Star's total fractionation capacity at Mont Belvieu to 200,000 barrels per day.

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the "Panhandle Merger"), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union's obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million common units and 6.3 million F Units), and ETP (2.2 million Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings' guarantee of

$600 million of Regency senior notes.

Trunkline LNG Transaction

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014.

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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 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 recent acquisitions and 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 distributable cash flow to our Partnership for years to come. Lastly, we have established and executed on cost control measures to drive cost savings across our operations to generate additional distributable cash flow.

Our principal operations as of December 31, 2013 included the following segments:

- Intrastate transportation and storage – Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through 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.

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- Interstate transportation and storage – The majority of our interstate transportation and storage 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, FEP, Transwestern and Panhandle shippers have made long-term 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. 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.

- 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 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.

- Investment in Sunoco Logistics – Revenues are generated by charging tariffs for transporting refined products, crude oil and other hydrocarbons through our pipelines as well as by charging fees for terminalling services for refined products, crude oil and other hydrocarbons at our facilities. Revenues are also generated by acquiring and marketing crude oil and refined products. Generally, crude oil and refined products purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.
- Retail marketing – Revenue is principally generated from the sale of gasoline and middle distillates and the operation of convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States. These stores supplement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products.

Trends and Outlook

We remain focused on the full integration and optimization of our diversified asset portfolio to enhance unitholder value. Recently, we have taken advantage of numerous asset optimization opportunities through strategic transactions among us and our subsidiaries and/or affiliates, and we expect to continue to evaluate and execute on such opportunities. We will also continue to look for opportunities to simplify our organization, which may include additional sales or transfers of non-core assets or businesses. As we have in the past, we will evaluate growth projects and acquisitions as such opportunities may be identified in the future, and we intend to continue to maintain sufficient liquidity to allow us to fund such potential growth projects and acquisitions. We intend to continue our distribution rate increases maintaining a distribution coverage ratio of 1.05x, thereby promoting a prudent balance between distribution rate increases and enhanced financial flexibility and strength while maintaining our investment grade ratings.

We expect to see processing and throughput volumes increase over 2014 as numerous projects that have been placed in service recently continue to ramp up. We have announced growth projects aggregating to $830 million that are expected to be placed in service through 2014 primarily in our midstream and NGL transportation and services segments, in which we plan to invest $575 million to $630 million in 2014 which we expect to drive growth over the next several years.

Regarding industry trends, we expect natural gas and NGL prices to remain within a range similar to recent history, as numerous forces impact both the supply and demand of natural gas and NGLs, including the ongoing economic recovery, coal to gas switching for power generation, exports to Mexico, conversion of natural gas pipelines to more profitable commodities, and increasing supply of natural gas from shale developments and associated gas from crude oil wells.

We expect to see continued opportunities related to wet or rich natural gas from shale formations, as well as continued demand for NGL related services, including storage, fractionation and exportation. In addition, we anticipate significant demand for crude transportation to the Gulf Coast markets. Consequently, these expectations will shape our strategic transactions and growth projects in the near term.

Results of Operations

We report Segment Adjusted EBITDA as a measure of segment performance. 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, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include 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 unconsolidated affiliates based on the Partnership’s proportionate ownership.

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.

During the fourth quarter 2013, management realigned the composition of our reportable segments, and as a result, our natural gas marketing operations are now aggregated into the “all other” segment. These operations were previously reported in the midstream segment. Based on this change in our segment presentation, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation. See Note 14 to our consolidated financial statements for additional financial information about our segments.

In accordance with GAAP, we have accounted for the Holdco Transaction, whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP’s consolidated financial statements have been retrospectively adjusted to reflect consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union).

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Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Consolidated Results

	Years Ended December 31,		
	2013	2012	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$464	$601	$(137)
Interstate transportation and storage	1,269	1,013	256
Midstream	479	467	12
NGL transportation and services	351	209	142
Investment in Sunoco Logistics	871	219	652
Retail marketing	325	109	216
All other	194	126	68
Total	3,953	2,744	1,209
Depreciation and amortization	(1,032)	(656)	(376)
Interest expense, net of interest capitalized	(849)	(665)	(184)
Gain on deconsolidation of Propane Business	—	1,057	(1,057)
Gain on sale of AmeriGas common units	87	—	87
Goodwill impairment	(689)	—	(689)
Gains (losses) on interest rate derivatives	44	(4)	48
Non-cash unit-based compensation expense	(47)	(42)	(5)
Unrealized gains (losses) on commodity risk management activities	51	(9)	60
LIFO valuation adjustments	3	(75)	78
Loss on extinguishment of debt	—	(115)	115
Non-operating environmental remediation	(168)	—	(168)
Adjusted EBITDA related to discontinued operations	(76)	(99)	23
Adjusted EBITDA related to unconsolidated affiliates	(629)	(480)	(149)
Equity in earnings of unconsolidated affiliates	172	142	30
Other, net	12	22	(10)
Income from continuing operations before income tax expense	832	1,820	(988)
Income tax expense from continuing operations	(97)	(63)	(34)
Income from continuing operations	735	1,757	(1,022)
Income (loss) from discontinued operations	33	(109)	142
Net income	$768	$1,648	$(880)

See the detailed discussion of Segment Adjusted EBITDA below.

The year ended December 31, 2012 was impacted by multiple transactions. Additional information has been provided in “Supplemental Pro Forma Information” below, which provides pro forma information assuming the transactions had occurred at the beginning of the period.

Depreciation and Amortization. Depreciation and amortization increased primarily as a result of acquisitions and growth projects including:

- depreciation and amortization related to Southern Union of $189 million in 2013 compared to $179 million from March 26, 2012 through December 31, 2012;
- depreciation and amortization related to Sunoco Logistics of $265 million in 2013 compared to $63 million from October 5, 2012 through December 31, 2012;

- depreciation and amortization related to Sunoco of $113 million in 2013 compared to $32 million from October 5, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2013 and 2012.

Interest Expense. Interest expense increased primarily due to:

- interest expense related to Sunoco Logistics of $76 million in 2013 compared to $14 million from October 5, 2012 through December 31, 2012;
- interest expense related to Sunoco of $33 million in 2013 compared to $9 million from October 5, 2012 through December 31, 2012;
- incremental interest expense due to the issuance of $1.25 billion of senior notes in January 2013 and the issuance of $1.5 billion of senior notes in September 2013; and
- a decrease in capitalized interest related to growth projects placed into service.

Gain on Deconsolidation of Propane Business. A gain on deconsolidation was recognized as a result of the contribution of our Propane Business to AmeriGas in January 2012.

Gain on Sale of AmeriGas Common Units. In July 2013, we sold 7.5 million of the AmeriGas common units that we originally received in connection with the contribution of our Propane Business to AmeriGas in January 2012. We recorded a gain based on the sale proceeds in excess of the carrying amount of the units sold.

Goodwill Impairment. In 2013, Trunkline LNG recorded a $689 million goodwill impairment. The decline in the estimated fair value was primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount.

Gains (Losses) on Interest Rate Derivatives. Gains on interest rate derivatives during the year ended December 31, 2013 resulted from increases in forward interest rates, which caused our forward-starting swaps to increase in value. These swaps are marked to fair value for accounting purposes with changes in value recorded in earnings each period. Conversely, decreases in forward interest rates resulted in losses on interest rate derivatives during the year ended December 31, 2012.

Unrealized Gains (Losses) on Commodity Risk Management Activities. See discussion included in the analysis of segment results below.

LIFO Valuation Adjustments. LIFO valuation reserve adjustments were recorded for the inventory associated with Sunoco's retail marketing operations as a result of commodity price changes between periods.

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized in January 2012 in connection with our tender offers in which we repurchased approximately $750 million in aggregate principal amount of Senior Notes.

Non-Operating Environmental Remediation. Non-operating environmental remediation was primarily related to Sunoco's recognition of environmental obligations related to closed sites.

Adjusted EBITDA Related to Discontinued Operations. In 2013, amounts reflected Southern Union's distribution operations through the date of sale. Southern Union completed the sales of the assets of MGE in September 2013 and the assets of NEG in December 2013. In 2012, amounts reflected the operations of Canyon, which was sold in October 2012, and, for the period from March 26, 2012 to December 31, 2012, Southern Union's distribution operations.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected for 2013 primarily include our proportionate share of such amounts related to AmeriGas, Citrus, FEP and Regency. The 2012 amounts primarily represented our proportionate share of such amounts for AmeriGas, Citrus (beginning March 26, 2012) and FEP. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

Other, net. Other, net in 2013 was primarily related to biodiesel tax credits recorded by Sunoco, amortization of regulatory assets and other income and expense amounts. Other, net in 2012 was primarily related to Southern Union's recognition of a net curtailment gain of $15 million related to its postretirement benefit plans.

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Income Tax Expense. Income tax expense increased primarily due to the acquisitions of Southern Union and Sunoco in 2012, both of which are taxable corporations.

Supplemental Information on Unconsolidated Affiliates

The following table presents equity in earnings of unconsolidated affiliates, the proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes by unconsolidated affiliate, Adjusted EBITDA related to unconsolidated affiliates and distributions received from affiliates for the years ended December 31, 2013 and 2012:

	Years Ended December 31,		
	2013	2012	Change
Equity in earnings (losses) of unconsolidated affiliates:			
AmeriGas	$50	$(4)	$54
Citrus	87	65	22
FEP	55	55	—
Regency	8	—	8
Other	(28)	26	(54)
Total equity in earnings of unconsolidated affiliates	$172	$142	$30
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:			
AmeriGas	$125	$143	$(18)
Citrus	209	163	46
FEP	20	22	(2)
Regency	58	—	58
Other	45	10	35
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$457	$338	$119
Adjusted EBITDA related to unconsolidated affiliates:			
AmeriGas	$175	$139	$36
Citrus	296	228	68
FEP	75	77	(2)
Regency	66	—	66
Other	17	36	(19)
Total Adjusted EBITDA related to unconsolidated affiliates	$629	$480	$149
Distributions received from unconsolidated affiliates:			
AmeriGas	$86	$94	$(8)
Citrus	175	88	87
FEP	69	70	(1)
Regency	44	—	44
Other	90	10	80
Total distributions received from unconsolidated affiliates	$464	$262	$202

Segment Operating Results

Our reportable segments are discussed below. "All other" includes our compression operations, our investment in AmeriGas, Southern Union's local distribution operations, our approximate 33% non-operating interest in PES, our investment in Regency, our natural gas marketing operations and our wholesale propane businesses.

In 2013, certain costs previously reported as selling, general and administrative expenses were reclassified to operating expenses. These costs include support functions such as engineering, environmental services, maintenance and reliability, pipeline integrity, procurement and technical services. Prior period amounts have been reclassified to conform to the current year presentation.

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On January 12, 2012, we received an equity investment in AmeriGas as partial consideration for the contribution of our Propane Business to AmeriGas. As a result, our all other segment includes eleven days of consolidated activity related to our Propane Business for the year ended December 31, 2012. Amounts attributable to our investment in AmeriGas are reflected above in “Supplemental Information on Unconsolidated Affiliates.”

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 amounts represent 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 expenses. 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.

For additional information regarding our business segments, see “Item 1. Business” and Notes 1 and 14 to our consolidated financial statements.

Intrastate Transportation and Storage

	Years Ended December 31,		
	2013	2012	Change
Natural gas transported (MMBtu/d)	9,455,878	9,849,900	(394,022)
Revenues	$2,452	$2,191	$261
Cost of products sold	1,737	1,394	343
Gross margin	715	797	(82)
Unrealized (gains) losses on commodity risk management activities	(39)	19	(58)
Operating expenses, excluding non-cash compensation expense	(189)	(191)	2
Selling, general and administrative expenses, excluding non-cash compensation expense	(23)	(25)	2
Adjusted EBITDA related to unconsolidated affiliates	—	1	(1)
Segment Adjusted EBITDA	$464	$601	$(137)

Volumes. Transported volumes decreased due to the cessation of certain long-term contracts, the impact of which was partially offset by the impact from a more favorable pricing environment. The average spot price at the Houston Ship Channel for 2013 increased to $3.70/MMBtu from $2.70/MMBtu for 2012, while the average basis differential between West Texas and the Houston Ship Channel increased from $0.02/MMBtu in 2012 to $0.05/MMBtu in 2013.

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

	Years Ended December 31,		
	2013	2012	Change
Transportation fees	$491	$550	$(59)
Natural gas sales and other	80	95	(15)
Retained fuel revenues	96	79	17
Storage margin, including fees	48	73	(25)
Total gross margin	$715	$797	$(82)

Our 2013 margin decreased as compared to 2012 due to the net impact of the following factors:

- Transportation fees. Transportation fees decreased primarily due to lower volumes resulting from the cessation of certain long-term transportation contracts and lower volumes transported through our pipeline systems as a result of a continued unfavorable natural gas price environment.

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 $21 million and $28 million in the years ended December 31, 2013 and 2012, respectively.

- Natural gas sales and other. Margin from 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. Margin from natural gas sales and other decreased primarily due to a reduction in the margin from derivatives used to hedge transportation activities.
- Retained fuel revenues. 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 fuel revenue increased primarily due to higher average natural gas spot prices.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2013	2012	Change
Withdrawals from storage natural gas inventory (MMBtu)	36,962,300	12,887,906	24,074,394
Realized margin on natural gas inventory transactions	$(16)	$75	$(91)
Fair value inventory adjustments	28	27	1
Unrealized gains (losses) on derivatives	8	(59)	67
Margin recognized on natural gas inventory, including related derivatives	20	43	(23)
Revenues from fee-based storage	28	31	(3)
Other costs	—	(1)	1
Total storage margin	$48	$73	$(25)

The decrease in our storage margin was principally driven by a decline in the spreads between the spot and forward prices on natural gas we own in the Bammel storage facility. Additionally, we experienced a decline in fee-based storage revenue of $3 million in 2013 due to the cessation of fixed fee storage contracts in 2012 and 2013.

Unrealized (Gains) 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. We experienced an increase of $58 million in the margin from unrealized gains and losses on commodity risk management activities in 2013 as compared to 2012. For 2013, unrealized gains on derivatives were $11 million, while unrealized gains from fair value adjustments to storage gas inventory were $28 million. For 2012, unrealized losses from derivatives of $46 million were offset by fair value adjustments to storage gas inventory of $27 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased primarily due to employee-related costs.

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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 employee-related costs.

Interstate Transportation and Storage

	Years Ended December 31,		
	2013	2012	Change
Natural gas transported (MMBtu/d)	6,428,574	6,811,339	(382,765)
Natural gas sold (MMBtu/d)	18,835	18,065	770
Revenues	$1,309	$1,109	$200
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(334)	(257)	(77)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(78)	(143)	65
Adjusted EBITDA related to unconsolidated affiliates	372	304	68
Segment Adjusted EBITDA	$1,269	$1,013	$256

Volumes. For the year ended December 31, 2013 compared to the prior year, transported volumes decreased on the Tiger pipeline due to declines in supply, and transported volumes decreased on the Transwestern pipeline primarily due to a customer outage on the west end of the pipeline and lower basis differentials primarily on the eastern side of the pipeline. These decreases were partially offset by transportation volume increases on the Panhandle Eastern and Trunkline Gas pipelines primarily due to higher basis differentials and increased volumes from the offshore consolidation of the Sea Robin pipeline.

Revenues. Interstate transportation and storage revenues increased for the year ended December 31, 2013 compared to the prior year primarily due to the consolidation of Southern Union’s transportation and storage operations beginning March 26, 2012 and the recognition of $52 million received in connection with the buyout of a Southern Union customer’s contract. The increase was offset slightly by a decrease in revenues of $8 million primarily related to the Transwestern pipeline.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Interstate transportation and storage operating expenses increased primarily due to the consolidation of Southern Union’s transportation and storage operations beginning March 26, 2012.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage selling, general and administrative expenses decreased primarily due to Southern Union’s recognition of merger-related expenses of $43 million during 2012. Additionally, selling, general and administrative expenses decreased as a result of cost reduction initiatives in 2013. These decreases were partially offset by the impact of consolidating Southern Union’s transportation and storage operations for only a partial period in 2012. With respect to the Transwestern and Tiger pipelines, selling, general and administrative expenses were approximately $4 million lower for 2013 compared to 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased primarily due to our acquisition of a 50% interest in Citrus which contributed $296 million during the year ended December 31, 2013 compared to $228 million during the prior year.

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Midstream

	Years Ended December 31,		
	2013	2012	Change
Gathered volumes (MMBtu/d):			
ETP legacy assets	2,610,409	2,364,133	246,276
Southern Union gathering and processing[(1)]	492,586	510,061	(17,475)
NGLs produced (Bbls/d):			
ETP legacy assets	111,226	79,640	31,586
Southern Union gathering and processing[(1)]	40,705	41,163	(458)
Equity NGLs produced (Bbls/d):			
ETP legacy assets	11,849	17,314	(5,465)
Southern Union gathering and processing[(1)]	7,459	7,437	22
Revenues	$2,249	$1,953	$296
Cost of products sold	1,579	1,273	306
Gross margin	670	680	(10)
Unrealized gains on commodity risk management activities	(7)	—	(7)
Operating expenses, excluding non-cash compensation expense	(167)	(165)	(2)
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(56)	36
Adjusted EBITDA related to discontinued operations	—	15	(15)
Adjusted EBITDA related to unconsolidated affiliates	—	(7)	7
Other	3	—	3
Segment Adjusted EBITDA	$479	$467	$12

(1) On April 30, 2013, Southern Union contributed its interest in SUGS to Regency and, as a result, Southern Union's gathering and processing operations were deconsolidated on April 30, 2013.

Volumes. Gathered volumes and NGL production for the ETP legacy assets increased for the year ended December 31, 2013 compared to the prior year primarily due to increased production by our customers in the Eagle Ford Shale area and also due to our increased capacity levels as a result of assets placed in service. The decrease in equity NGL production for ETP's legacy assets for the year ended December 31, 2013 compared to the prior year was primarily due to processing plants optimizing NGL recoveries in response to the current NGL price environment. Volumes from Southern Union's gathering and processing operations were reflected through the deconsolidation on April 30, 2013.

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

	Years Ended December 31,		
	2013	2012	Change
Gathering and processing fee-based revenues	$449	$339	$110
Non fee-based contracts and processing	220	335	(115)
Other	1	6	(5)
Total gross margin	$670	$680	$(10)

Midstream gross margin decreased 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 $125 million for the year ended December 31, 2013 compared to the prior year, which was offset by a decrease of $12 million resulting from the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.
- Non fee-based contracts and processing margin. Non fee-based margins decreased primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013 resulting in a decrease of $89 million. Non fee-

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based margins also decreased by $27 million primarily due to lower NGL prices on our Southeast Texas system. The composite NGL price for 2013 was $0.91 per gallon compared to $1.19 per gallon in 2012.

Unrealized Gains on Commodity Risk Management Activities. For the year ended December 31, 2013, our midstream segment recorded $6 million of unrealized gains associated with hedges that were de-designated during the year.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased primarily due to additional expenses from assets recently placed in service offset partially due to the impact of consolidating Southern Union's gathering and processing operations for four months during 2013 compared to nine months during 2012.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased primarily due to Southern Union's recognition of merger-related expenses of $16 million during 2012. The remainder of the decrease was due to the impact of consolidating Southern Union's gathering and processing operations for four months during 2013 compared to nine months during 2012.

NGL Transportation and Services

	Years Ended December 31,		
	2013	2012	Change
NGL transportation volumes (Bbls/d)	334,853	172,569	162,284
NGL fractionation volumes (Bbls/d)	101,967	17,754	84,213
Revenues	$2,127	$650	$1,477
Cost of products sold	1,655	361	1,294
Gross margin	472	289	183
Unrealized gains on commodity risk management activities	(1)	—	(1)
Operating expenses, excluding non-cash compensation expense	(115)	(66)	(49)
Selling, general and administrative expenses, excluding non-cash compensation expense	(10)	(14)	4
Adjusted EBITDA related to unconsolidated affiliates	5	—	5
Segment Adjusted EBITDA	$351	$209	$142

Volumes. NGL transportation volumes increased due to the completion of the Gateway and Justice pipelines in December 2012 and additional NGL production as a result of bringing our Jackson and Kenedy gas processing plants in service in February 2013 and December 2012, respectively. Average daily fractionated volumes increased due to the commissioning of Lone Star’s fractionators at Mont Belvieu, Texas. These volumes include all physical and contractual volumes where we collected a fractionation fee.

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

	Years Ended December 31,		
	2013	2012	Change
Transportation margin	$187	$80	$107
Processing and fractionation margin	142	81	61
Storage margin	137	129	8
Other margin	6	(1)	7
Total gross margin	$472	$289	$183

For the year ended December 31, 2013 compared to prior year, NGL transportation and services segment gross margin increased due to the following:

- Transportation margin. Transportation margin increased as a result of higher volumes transported out of West Texas due to the completion of the Gateway pipeline, which accounted for $73 million of the increase. The completion of the Justice pipeline connection to Mont Belvieu, Texas and additional NGL production from our processing plants accounted for the remainder of the $34 million increase in transportation margin.

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- Processing and fractionation margin. Processing and fractionation margin increased due to the startup of Lone Star's fractionators in Mont Belvieu, Texas in December 2012 and October 2013, which contributed an additional $85 million during the year ended December 2013. The increase in margin from Lone Star's fractionators was offset by a $24 million decrease in margin attributable to our fractionator in Geismar, Louisiana primarily due to lower volumes.

Operating Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services operating expenses increased in 2013 primarily due to additional expenses from assets recently placed in service.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services selling, general and administrative expenses decreased primarily due to the expiration of a transition services agreement and a decrease in employee related costs, including allocated overhead expenses.

Investment in Sunoco Logistics

	Years Ended December 31,		
	2013	2012	Change
Revenue	$16,639	$3,189	$13,450
Cost of products sold	15,574	2,885	12,689
Gross margin	1,065	304	761
Unrealized gains on commodity risk management activities	(1)	(15)	14
Operating expenses, excluding non-cash compensation expense	(117)	(48)	(69)
Selling, general and administrative expenses, excluding non-cash compensation expense	(110)	(32)	(78)
Adjusted EBITDA related to unconsolidated affiliates	41	10	31
Other	(7)	—	(7)
Segment Adjusted EBITDA	$871	$219	$652

We obtained control of Sunoco Logistics on October 5, 2012 in connection with our acquisition of Sunoco; therefore, the results for the year ended December 31, 2012 only reflect results from October 5, 2012 to December 31, 2012 compared to a full twelve months of results during the year ended December 31, 2013.

Retail Marketing

	Years Ended December 31,		
	2013	2012	Change
Total retail gasoline outlets, end of period	5,112	4,988	124
Total company-operated outlets, end of period	513	437	76
Gasoline and diesel throughput per company-operated site (gallons/month)	200,087	198,000	2,087
Revenue	$21,012	$5,926	$15,086
Cost of products sold	20,150	5,757	14,393
Gross margin	862	169	693
Unrealized gains on commodity risk management activities	(1)	—	(1)
Operating expenses, excluding non-cash compensation expense	(435)	(119)	(316)
Selling, general and administrative expenses, excluding non-cash compensation expense	(101)	(17)	(84)
LIFO valuation adjustments	(3)	75	(78)
Adjusted EBITDA related to unconsolidated affiliates	4	1	3
Other	(1)	—	(1)
Segment Adjusted EBITDA	$325	$109	$216

We acquired our retail marketing segment on October 5, 2012 in connection with our acquisition of Sunoco; therefore, the results for the year ended December 31, 2012 only reflect results from October 5, 2012 to December 31, 2012 compared to a full twelve

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months of results during the year ended December 31, 2013. Segment Adjusted EBITDA also increased by $10 million as a result of the MACS acquisition in October 2013.

All Other

	Years Ended December 31,		
	2013	2012	Change
Revenue	$2,367	$1,555	$812
Cost of products sold	2,309	1,496	813
Gross margin	58	59	(1)
Unrealized (gains) losses on commodity risk management activities	(2)	5	(7)
Operating expenses, excluding non-cash compensation expense	(31)	(57)	26
Selling, general and administrative expenses, excluding non-cash compensation expense	(106)	(119)	13
Adjusted EBITDA related to discontinued operations	76	84	(8)
Adjusted EBITDA related to unconsolidated affiliates	213	166	47
Other	(4)	—	(4)
Elimination	(10)	(12)	2
Segment Adjusted EBITDA	$194	$126	$68

Amounts reflected in our all other segment primarily include:

- our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas in January 2012. Our investment in AmeriGas was reflected in the all other segment subsequent to that transaction;
- Southern Union’s local distribution operations beginning March 26, 2012;
- our natural gas compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture, effective upon our acquisition of Sunoco on October 5, 2012;
- our investment in Regency related to the Regency common and Class F units received by Southern Union in exchange of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013; and
- our natural gas marketing operations.

The decrease in operating expenses for the year ended December 31, 2013 compared to last year was primarily due to the recognition of $18 million of operating expenses from our retail propane operations prior to the deconsolidation of those operations in January 2012.

Selling, general and administrative expenses include corporate expenses as well as amounts related to the retail propane, local distribution and natural gas compression operations.

Adjusted EBITDA related to discontinued operations reflected the results of Southern Union's local distribution operations.

Adjusted EBITDA related to unconsolidated affiliates reflected the results from our investments in AmeriGas, PES and Regency beginning in January 2012, October 2012 and April 2013, respectively. The increase in Adjusted EBITDA related to unconsolidated affiliates was primarily related to our investments in AmeriGas and Regency. Additional information related to unconsolidated affiliates is provided above in “Supplemental Information on Unconsolidated Affiliates.”

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Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011

Consolidated Results

	Years Ended December 31,		
	2012	2011	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$601	$667	$(66)
Interstate transportation and storage	1,013	373	640
Midstream	467	421	46
NGL transportation and services	209	127	82
Investment in Sunoco Logistics	219	—	219
Retail marketing	109	—	109
All other	126	193	(67)
Total	2,744	1,781	963
Depreciation and amortization	(656)	(405)	(251)
Interest expense, net of interest capitalized	(665)	(474)	(191)
Gain on deconsolidation of Propane Business	1,057	—	1,057
Losses on interest rate derivatives	(4)	(77)	73
Non-cash unit-based compensation expense	(42)	(38)	(4)
Unrealized losses on commodity risk management activities	(9)	(11)	2
LIFO valuation adjustments	(75)	—	(75)
Loss on extinguishment of debt	(115)	—	(115)
Adjusted EBITDA related to discontinued operations	(99)	(23)	(76)
Adjusted EBITDA related to unconsolidated affiliates	(480)	(56)	(424)
Equity in earnings of unconsolidated affiliates	142	26	116
Other, net	22	(4)	26
Income from continuing operations before income tax expense	1,820	719	1,101
Income tax expense from continuing operations	(63)	(19)	(44)
Income from continuing operations	1,757	700	1,057
Loss from discontinued operations	(109)	(3)	(106)
Net income	$1,648	$697	$951

See the detailed discussion of Segment Adjusted EBITDA below.

The year ended December 31, 2012 was impacted by multiple transactions. Additional information has been provided in “Supplemental Pro Forma Information” below, which provides pro forma information assuming the transactions had occurred at the beginning of the period.

Depreciation and Amortization. Depreciation and amortization increased primarily due to:

- depreciation and amortization related to Southern Union of $179 million from March 26, 2012 through December 31, 2012;
- depreciation and amortization related to Sunoco Logistics and Sunoco of $63 million and $32 million, respectively, from October 5, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2011 and 2012.

These increases in depreciation and amortization were offset by the impact from the January 2012 deconsolidation of the Propane Business, for which our consolidated results reflected $4 million and $82 million in depreciation and amortization for the years ended December 31, 2012 and 2011, respectively.

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Interest Expense. Interest expense increased primarily due to:

- interest expense recorded by Southern Union of $130 million from March 26, 2012 through December 31, 2012;
- interest expense related to Sunoco Logistics and Sunoco of $14 million and $9 million, respectively, from October 5, 2012 through December 31, 2012; and,
- incremental interest expense due to the issuance of $1.5 billion of senior notes in May 2011 to fund the LDH acquisition and the issuance of $2.0 billion of senior notes in January 2012 to fund the Citrus Acquisition; offset by
- a reduction of several series of our higher coupon notes that were repurchased in the tender offers completed in January 2012; and,
- an increase in capitalized interest related to our growth projects.

Gain on Deconsolidation of Propane Business. A gain on deconsolidation was recognized as a result of the contribution of our Propane Business to AmeriGas in January 2012.

Losses on Interest Rate Derivatives. Losses on interest rate derivatives decreased due to the recognition of losses in 2011 resulting from significant forward rate decreases during 2011.

LIFO Valuation Adjustments. LIFO valuation reserve adjustments were recorded for the inventory associated with Sunoco's retail marketing operations as a result of commodity price changes subsequent to the inventory being recorded at fair value in connection with purchase accounting.

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized in January 2012 in connection with our tender offers in which we repurchased approximately $750 million in aggregate principal amount of Senior Notes.

Adjusted EBITDA Related to Discontinued Operations. Amounts reflect the operations of Canyon, which was sold in October 2012, and, for the period from March 26, 2012 to December 31, 2012, Southern Union's distribution operations.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected for 2012 primarily include our proportionate share of such amounts related to AmeriGas, Citrus and FEP. The 2011 amounts primarily represented our proportionate share of such amounts for FEP only. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

Other, net. Other, net increased in 2012 primarily due to Southern Union's recognition of a net curtailment gain of $15 million related to its postretirement benefit plans.

Income Tax Expense. Income tax expense increased primarily due to the acquisitions of Southern Union and Sunoco in 2012, both of which are taxable corporations.

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Supplemental Information on Unconsolidated Affiliates

The following table presents equity in earnings of unconsolidated affiliates, the proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes by unconsolidated affiliate, Adjusted EBITDA related to unconsolidated affiliates and distributions received from affiliates for the years ended December 31, 2012 and 2011:

	Years Ended December 31,		
	2012	2011	Change
Equity in earnings (losses) of unconsolidated affiliates:			
AmeriGas	$(4)	$—	$(4)
Citrus	65	—	65
FEP	55	24	31
Other	26	2	24
Total equity in earnings of unconsolidated affiliates	$142	$26	$116
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:			
AmeriGas	$143	$—	$143
Citrus	163	—	163
FEP	22	29	(7)
Other	10	1	9
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$338	$30	$308
Adjusted EBITDA related to unconsolidated affiliates:			
AmeriGas	$139	$—	$139
Citrus	228	—	228
FEP	77	53	24
Other	36	3	33
Total Adjusted EBITDA related to unconsolidated affiliates	$480	$56	$424
Distributions received from unconsolidated affiliates:			
AmeriGas	$94	$—	$94
Citrus	88	—	88
FEP	70	46	24
Other	10	5	5
Total distributions received from unconsolidated affiliates	$262	$51	$211

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Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)	9,849,900	11,295,084	(1,445,184)
Revenues	$2,191	$2,674	$(483)
Cost of products sold	1,394	1,774	(380)
Gross margin	797	900	(103)
Unrealized losses on commodity risk management activities	19	9	10
Operating expenses, excluding non-cash compensation expense	(191)	(210)	19
Selling, general and administrative, excluding non-cash compensation expense	(25)	(35)	10
Adjusted EBITDA related to unconsolidated affiliates	1	3	(2)
Segment Adjusted EBITDA	$601	$667	$(66)

Volumes. We experienced a decrease in transport volumes in 2012 due to a less favorable natural gas price environment, the cessation of certain long-term contracts, and lower basis differentials primarily between the West and East Texas hubs. The average spot price at the Houston Ship Channel for 2012 declined to $2.70/MMBtu from $3.94/MMBtu for 2011, while the average basis differential between West Texas and the Houston Ship Channel decreased from $0.035/MMBtu in 2011 to $0.019/MMBtu in 2012.

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

	Years Ended December 31,		
	2012	2011	Change
Transportation fees	$550	$599	$(49)
Natural gas sales and other	95	107	(12)
Retained fuel revenues	79	130	(51)
Storage margin, including fees	73	64	9
Total gross margin	$797	$900	$(103)

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

- Transportation fees. Transport fees decreased primarily due to a decrease in transported volumes as unfavorable market conditions continued and the cessation of certain long-term transportation contracts;

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 $28 million in 2012 compared to $36 million in 2011. The decrease of $8 million between periods was primarily due to a reduction in the amount of capacity utilized by our marketing affiliate;

- Natural gas sales and other. Margin from natural gas sales and other activity decreased primarily due to a decline of $30 million in margin where we utilize third party processing, offset by increased margin of $13 million from wellhead purchases in the Eagle Ford Shale that were sold to end users on our HPL system and increased margin of $4 million from system optimization and other operational 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. Excluding derivatives related to storage, unrealized gains of $13 million were recorded in 2012 as compared to unrealized losses of $21 million in 2011; and

- Retained fuel revenues. 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 $51 million due to less retained volumes and a $37 million decline in the average of natural gas spot prices.

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Storage margin was comprised of the following:

	Years Ended December 31,		
	2012	2011	Change
Withdrawals from storage natural gas inventory (MMBtu)	12,887,906	24,517,008	(11,629,102)
Realized margin on natural gas inventory transactions	$75	$19	$56
Fair value inventory adjustments	27	(52)	79
Unrealized gains (losses) on derivatives	(59)	63	(122)
Margin recognized on natural gas inventory, including related derivatives	43	30	13
Revenues from fee-based storage	31	35	(4)
Other costs	(1)	(1)	—
Total storage margin	$73	$64	$9

The increase in our storage margin was principally driven by gains on settled derivatives which offset a decline in margin on the physical sale of storage gas due to a decrease in volumes withdrawn from our Bammel storage facility. Additionally, we experienced a decline in fee-based storage revenue due to the cessation of 4.5 Bcf of fixed fee storage contracts in 2011.

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. For 2012, unrealized losses on derivatives of $46 million were offset by fair value adjustments to storage gas inventory of $27 million. For 2011, unrealized losses reflected fair value adjustments to storage gas inventory of $52 million, offset by gains on derivatives of $42 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased primarily due to a decrease in natural gas consumed for compression of $16 million due to lower spot prices and a decrease in ad valorem taxes of $3 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 employee-related costs and allocated overhead expenses.

Interstate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)	6,811,339	2,800,655	4,010,684
Natural gas sold (MMBtu/d)	18,065	22,405	(4,340)
Revenues	$1,109	$447	$662
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(257)	(103)	(154)
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(143)	(24)	(119)
Adjusted EBITDA related to unconsolidated affiliates	304	53	251
Segment Adjusted EBITDA	$1,013	$373	$640

Volumes. Transported volumes increased significantly due to the consolidation of Southern Union's transportation and storage businesses beginning March 26, 2012. Transported volumes for the Transwestern and Tiger pipelines increased by 177,755 MMBtu/d primarily due to the recent Tiger pipeline expansion.

Revenues. Southern Union's transportation and storage business recognized revenues of $592 million from March 26, 2012 through December 31, 2012. Tiger pipeline revenues also increased approximately $91 million primarily due to incremental reservation fees related to the Tiger pipeline expansion. These increases were offset slightly by a decrease in operational gas sales on the Transwestern pipeline.

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Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Substantially all of the increase was due to the consolidation of Southern Union's transportation and storage business beginning March 26, 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Substantially all of the increase was due to the consolidation of Southern Union's transportation and storage business beginning March 26, 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased primarily due to our acquisition of a 50% interest in Citrus which contributed $228 million during the year ended December 31, 2012. In addition, Adjusted EBITDA related to FEP increased $24 million primarily due to an increase in demand fees as a result of incremental volume commitments in our shippers' take or pay contracts.

Midstream

	Years Ended December 31,		
	2012	2011	Change
Gathered volumes (MMBtu/d):			
ETP legacy assets	2,364,133	2,020,126	344,007
Southern Union gathering and processing	510,061	—	510,061
NGLs produced (Bbls/d):			
ETP legacy assets	79,640	54,246	25,394
Southern Union gathering and processing	41,163	—	41,163
Equity NGLs produced (Bbls/d):			
ETP legacy assets	17,314	16,385	929
Southern Union gathering and processing	7,437	—	7,437
Revenues	$1,953	$1,483	$470
Cost of products sold	1,273	988	285
Gross margin	680	495	185
Operating expenses, excluding non-cash compensation expense	(165)	(87)	(78)
Selling, general and administrative, excluding non-cash compensation expense	(56)	(10)	(46)
Adjusted EBITDA related to discontinued operations	15	23	(8)
Adjusted EBITDA related to unconsolidated affiliates	(7)	—	(7)
Segment Adjusted EBITDA	$467	$421	$46

Volumes. NGL production increased primarily due to increased inlet volumes as a result of more production by our customers in the Eagle Ford Shale area and increased capacity from recent completed projects. The increase in equity NGL production was primarily due to the higher production partially offset by a higher concentration of volumes billed under fee-based contracts in 2012 as compared to 2011. Additionally, in conjunction with the Holdco Transaction, Southern Union's gathering and processing operations were retrospectively consolidated into our midstream segment beginning March 26, 2012. For the period from March 26, 2012 to December 31, 2012, NGL production averaged 41,163 Bbls/d for Southern Union's gathering and processing operations.

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

	Years Ended December 31,		
	2012	2011	Change
Gathering and processing fee-based revenues	$339	$253	$86
Non fee-based contracts and processing	335	234	101
Other	6	8	(2)
Total gross margin	$680	$495	$185

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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 $70 million in 2012 as compared to 2011, partially offset by declines in the Fort Worth Basin that affected our North Texas system resulting in a $5 million decline from 2012 to 2011. Additionally, Southern Union's gathering and processing segment contributed $20 million of fee-based revenue during March 26, 2012 through December 31, 2012.
- Non fee-based contracts and processing margin. We recorded $125 million of incremental non-fee based revenue in connection with the consolidation of Southern Union's gathering and processing business from March 26, 2012 through December 31, 2012. Excluding these incremental revenues from Southern Union's gathering and processing business, our non fee-based gross margins decreased $24 million primarily due to lower NGL prices. The composite NGL price for 2012 was $0.96 per gallon as compared to $1.30 per gallon in 2011.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased primarily due to the consolidation of Southern Union's gathering and processing operations effective March 26, 2012. In addition, growth in the Eagle Ford Shale region resulted in $6 million of additional operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to consolidation of Southern Union's gathering and processing operations effective March 26, 2012. For the periods presented, selling, general and administrative expenses increased approximately $38 million due to consolidation of Southern Union's gathering and processing operations. In addition, growth from assets placed into service in the Eagle Ford Shale resulted in $8 million of additional selling, general and administrative expenses.

NGL Transportation and Services

	Years Ended December 31,		
	2012	2011	Change
NGL transportation volumes (Bbls/d)	172,569	132,862	39,707
NGL fractionation volumes (Bbls/d)	17,754	16,475	1,279
Revenues	$650	$397	$253
Cost of products sold	361	218	143
Gross margin	289	179	110
Operating expenses, excluding non-cash compensation expense	(66)	(43)	(23)
Selling, general and administrative, excluding non-cash compensation expense	(14)	(9)	(5)
Adjusted EBITDA related to unconsolidated affiliates	—	—	—
Segment Adjusted EBITDA	$209	$127	$82

Our NGL Transportation and Services segment reflected the results from Lone Star, which was formed in 2011 and acquired all of the membership interests in LDH on May 2, 2011, as well as multiple other wholly-owned or joint venture pipelines that have recently become operational.

Volumes. The volumes reflected above for the year ended December 31, 2012 represent average daily volumes for the period from May 2, 2011 to December 31, 2012. NGL transportation volumes increased for the year ended December 31, 2012 as compared to the same period in the prior year primarily due to an increase in volumes transported on our wholly-owned and joint venture NGL pipelines originating from our La Grange and Chisholm processing plants as a result of more production from the Eagle Ford area. Average daily fractionated volumes increased for the year ended December 31, 2012 as compared to the year ended December 31, 2011 at our Geismar fractionation complex in Louisiana due to less refinery downtime in 2012 as compared to the comparable prior year period.

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

	Years Ended December 31,		
	2012	2011	Change
Transportation margin	$80	$33	$47
Processing and fractionation margin	81	53	28
Storage margin	129	93	36
Other margin	(1)	—	(1)
Total gross margin	$289	$179	$110

For the year ended December 31, 2012 compared to the same period in the prior year, NGL transportation and services segment gross margin reflected twelve months of activity compared to only eight months of activity in 2011. Additionally, gross margin for the year ended December 31, 2012 was impacted by the following items which did not have a comparable impact in the prior period:

- Incurred a $2 million lower-of-cost or market write down on inventory held as of June 30, 2012 in our storage facility and pipelines;
- Hurricane Isaac resulted in an approximate $4 million decrease to our processing and fractionation margin; and
- The Freedom Pipeline and Liberty Pipeline, which were placed in service in 2012, and Justice Pipeline, which began interim service in 2012, contributed $12 million in the aggregate for the year ended December, 31, 2012.

The Lone Star West Texas Gateway pipeline and the Lone Star Fractionator I were both placed in service in December 2012; therefore, the gross margin impact in 2012 was not significant.

Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses increased due to operations of Lone Star for twelve months in 2012 compared to eight months in 2011. The Lone Star West Texas Gateway pipeline and the Lone Star Fractionator I were both placed in service in December 2012; therefore, the operating expense impact in 2012 was not significant.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL Transportation and Storage selling, general and administrative expenses increased due to operations of Lone Star for twelve months in 2012 compared to eight months in 2011.

Investment in Sunoco Logistics

	Years Ended December 31,		
	2012	2011	Change
Revenue	$3,189	$—	$3,189
Cost of products sold	2,885	—	2,885
Gross margin	304	—	304
Unrealized gains on commodity risk management activities	(15)	—	(15)
Operating expenses, excluding non-cash compensation expense	(48)	—	(48)
Selling, general and administrative, excluding non-cash compensation expense	(32)	—	(32)
Adjusted EBITDA related to unconsolidated affiliates	10	—	10
Segment Adjusted EBITDA	$219	$—	$219

We obtained control of Sunoco Logistics on October 5, 2012 in connection with our acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

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Retail Marketing

	Years Ended December 31,		
	2012	2011	Change
Total retail gasoline outlets, end of period	4,988	—	4,988
Total company-operated outlets, end of period	437	—	437
Gasoline and diesel throughput per company-operated site (gallons/month)	198,000	—	198,000
Revenue	$5,926	$—	$5,926
Cost of products sold	5,757	—	5,757
Gross margin	169	—	169
Operating expenses, excluding non-cash compensation expense	(119)	—	(119)
Selling, general and administrative, excluding non-cash compensation expense	(17)	—	(17)
LIFO valuation adjustments	75	—	75
Adjusted EBITDA related to unconsolidated affiliates	1	—	1
Segment Adjusted EBITDA	$109	$—	$109

We obtained control of our retail marketing segment on October 5, 2012 in connection with our acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

All Other

	Years Ended December 31,		
	2012	2011	Change
Revenue	$1,555	$2,888	$(1,333)
Cost of products sold	1,496	2,274	(778)
Gross margin	59	614	(555)
Unrealized losses on commodity risk management activities	5	1	4
Operating expenses, excluding non-cash compensation expense	(57)	(355)	298
Selling, general and administrative, excluding non-cash compensation expense	(119)	(57)	(62)
Adjusted EBITDA related to discontinued operations	84	—	84
Adjusted EBITDA related to unconsolidated affiliates	166	—	166
Elimination	(12)	(10)	(2)
Segment Adjusted EBITDA	$126	$193	$(67)

For 2011, our all other segment included our retail propane and other retail propane business, as well as certain other businesses. In January 2012, we contributed the Propane Business to AmeriGas. In 2012, amounts reflected in our all other segment primarily include:

- our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas in January 2012. Our investment in AmeriGas was reflected in the all other segment subsequent to that transaction;
- Southern Union’s local distribution operations beginning March 26, 2012;
- our natural gas compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture, effective upon our acquisition of Sunoco on October 5, 2012; and
- our natural gas marketing operations.

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Supplemental Pro Forma Financial Information

The following unaudited pro forma consolidated financial information of ETP has been prepared in accordance with Article 11 of Regulation S-X and reflects the pro forma impacts of the Propane Transaction, Sunoco Merger and Holdco Transaction for the year ended December 31, 2012 and 2011, giving effect that each occurred on January 1, 2011. This unaudited pro forma financial information is provided to supplement the discussion and analysis of the historical financial information and should be read in conjunction with such historical financial information. This unaudited pro forma information is for illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Sunoco Merger and Holdco Transaction had been consummated on January 1, 2011.

The following table presents the pro forma financial information for the year ended December 31, 2012:

	ETP Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$15,702	$(93)	$35,258	$443	$(12,174)	$39,136
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	13,217	(80)	33,142	302	(11,193)	35,388
Depreciation and amortization	656	(4)	168	49	76	945
Selling, general and administrative	435	(1)	459	11	(119)	785
Impairment charges	—		124		(22)	102
Total costs and expenses	14,308	(85)	33,893	362	(11,258)	37,220
OPERATING INCOME	1,394	(8)	1,365	81	(916)	1,916
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(665)	(24)	(123)	(50)	2	(860)
Equity in earnings of affiliates	142	19	41	16	5	223
Gain on deconsolidation of Propane Business	1,057	(1,057)	—	—	—	—
Gain on formation of Philadelphia Energy Solutions	—	—	1,144	—	(1,144)	—
Loss on extinguishment of debt	(115)	115	—	—	—	—
Losses on interest rate derivatives	(4)	—	—	—	—	(4)
Other, net	11	2	118	(2)	(2)	127
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	1,820	(953)	2,545	45	(2,055)	1,402
Income tax expense (benefit)	63	—	956	12	(871)	160
INCOME FROM CONTINUING OPERATIONS	$1,757	$(953)	$1,589	$33	$(1,184)	$1,242

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The following table presents the pro forma financial information for the year ended December 31, 2011:

	ETP Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$6,799	$(1,427)	$45,328	$1,997	$(16,528)	$36,169
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	4,974	(1,174)	44,119	1,338	(16,677)	32,580
Depreciation and amortization	405	(78)	335	204	(2)	864
Selling, general and administrative	173	(47)	598	42	(56)	710
Impairment charges	—	—	2,629	—	(2,569)	60
Total costs and expenses	5,552	(1,299)	47,681	1,584	(19,304)	34,214
OPERATING INCOME	1,247	(128)	(2,353)	413	2,776	1,955
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(474)	(40)	(172)	(218)	29	(875)
Equity in earnings of affiliates	26	148	15	99	(158)	130
Losses on interest rate derivatives	(77)	—	—	—	—	(77)
Impairment charges	(5)	—	—	—	—	(5)
Other, net	2	2	44	—	(2)	46
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	719	(18)	(2,466)	294	2,645	1,174
Income tax expense (benefit)	19	(4)	(1,063)	80	1,070	102
INCOME FROM CONTINUING OPERATIONS	$700	$(14)	$(1,403)	$214	$1,575	$1,072

(a) Propane Transaction adjustments reflect the following:

- The adjustments reflect the deconsolidation of ETP's propane operations in connection with the Propane Transaction.
- The adjustments reflect the pro forma impacts from the consideration received in connection with the Propane Transaction, including ETP's receipt of AmeriGas common units and ETP's use of cash proceeds from the transaction to redeem long-term debt.
- The 2012 adjustments include the elimination of (i) the gain recognized by ETP in connection with the deconsolidation of the Propane Business and (ii) ETP's loss on extinguishment of debt recognized in connection with the use of proceeds to redeem of long-term debt.

(b) Sunoco historical amounts in 2012 include only the period from January 1, 2012 through September 30, 2012.

(c) Southern Union historical amounts in 2012 include only the period from January 1, 2012 through March 25, 2012.

(d) Substantially all of the Holdco pro forma adjustments relate to Sunoco's exit from its Northeast refining operations and formation of the PES joint venture, except for the following:

- The adjustment to depreciation and amortization reflects incremental amounts for estimated fair values recorded in purchase accounting related to Sunoco and Southern Union.
- The adjustment to selling, general and administrative expenses includes the elimination of merger-related costs incurred, because such costs would not have a continuing impact on results of operations.
- The adjustment to interest expense includes incremental amortization of fair value adjustments to debt recorded in purchase accounting.
-

The adjustment to equity in earnings of affiliates reflects the reversal of amounts related to Citrus Corp. recorded in Southern Union's historical income statements.

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- The adjustment to income tax expense includes the pro forma impact resulting from the pro forma adjustments to pre-tax income of Sunoco and Southern Union.

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 expect the following capital expenditures in 2014 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$30	$40	$25	$30
Interstate transportation and storage	20	30	115	135
Midstream	275	300	10	15
NGL transportation and services[1]	300	330	20	25
Investment in Sunoco Logistics	1,250	1,350	65	75
Retail Marketing	125	155	50	60
All other (including eliminations)	60	80	10	15
Total projected capital expenditures	$2,060	$2,285	$295	$355

(1) We expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $75 million and $100 million.

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, delays from steel 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 in our anticipated growth capital expenditures for each year.

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof.

As of December 31, 2013, in addition to $549 million of cash on hand, we had available capacity under our revolving credit facilities of $2.34 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 2014; 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.

Sunoco Logistics' primary sources of liquidity consist of cash generated from operating activities and borrowings under its $1.50 billion credit facility. At December 31, 2013, Sunoco Logistics had available borrowing capacity of $1.30 billion under its revolving credit facility. Sunoco Logistics' capital position reflects crude oil and refined products inventories based on historical costs under the last-in, first-out ("LIFO") method of accounting. Sunoco Logistics periodically supplements its cash flows from operations with proceeds from debt and equity financing activities.

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

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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 resulted 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 inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period:

Year Ended December 31, 2013

Cash provided by operating activities in 2013 was $2.37 billion and net income was $768 million. The difference between net income and cash provided by operating activities in 2013 primarily consisted of non-cash items totaling $1.52 billion offset by net changes in operating assets and liabilities of $146 million. The non-cash activity in 2013 consisted primarily of depreciation and amortization of $1.03 billion, a goodwill impairment of $689 million, and deferred income taxes of $48 million offset slightly by the gain on the sale of AmeriGas common units of $87 million.

Year Ended December 31, 2012

Cash provided by operating activities in 2012 was $1.20 billion and net income was $1.65 billion. The difference between net income and cash provided by operating activities in 2012 primarily consisted of the gain on deconsolidation of our Propane Business of $1.06 billion and net changes in operating assets and liabilities of $475 million offset by non-cash items totaling $1.10 billion. The non-cash activity in 2012 consisted primarily of depreciation and amortization, including amounts related to discontinued operations, of $656 million, the write-down of assets included in loss from discontinued operations of $132 million and non-cash compensation expense of $42 million.

Year Ended December 31, 2011

Cash provided by operating activities in 2011 was $1.34 billion and net income was $697 million. The difference between net income and cash provided by operating activities in 2011 consisted of non-cash items totaling $486 million and changes in operating assets and liabilities of $166 million. The non-cash activity in 2011 consisted primarily of depreciation and amortization, including amounts related to discontinued operations, of $431 million and non-cash compensation expense of $37 million.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash distributions from our joint ventures, and cash proceeds from sales or contributions of assets or businesses. 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, 2013

Cash used in investing activities in 2013 was $2.46 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $2.52 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, we received $504 million, $1.01 billion, and $346 million in cash from the SUGS Contribution, the sale of the MGE and NEG assets, and the sale of AmeriGas common units, respectively, and paid net cash of $1.74 billion for acquisitions, primarily for the Holdco Acquisition and MACS.

Year Ended December 31, 2012

Cash used in investing activities in 2012 was $2.29 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $2.81 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2012 we paid net cash of $1.36 billion for acquisitions, primarily including amounts related to Citrus and Sunoco. We also received net cash proceeds of $1.44 billion from the contribution of the Propane Business.

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 and net of contributions in aid of construction costs) were $1.39 billion. Additional detail related to our capital expenditures is provided in the table below. 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 million.
Following is a summary of our capital expenditures (net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Year Ended December 31, 2013:					
Intrastate transportation and storage	$18	$29	$47	$(3)	$44
Interstate transportation and storage	55	97	152	18	170
Midstream[(1)]	516	49	565	87	652
NGL transportation and services[(2)]	426	17	443	84	527
Investment in Sunoco Logistics	965	53	1,018	(121)	897
Retail marketing	113	63	176	(1)	175
All other (including eliminations)	19	35	54	4	58
Total	$2,112	$343	$2,455	$68	$2,523
Year Ended December 31, 2012:					
Intrastate transportation and storage	$8	$29	$37	$2	$39
Interstate transportation and storage	5	128	133	1	134
Midstream	1,265	52	1,317	(153)	1,164
NGL transportation and services	1,288	14	1,302	(75)	1,227
Investment in Sunoco Logistics	118	21	139	—	139
Retail marketing	38	20	58	(19)	39
All other (including eliminations)	14	49	63	—	63
Total	$2,736	$313	$3,049	$(244)	$2,805
Year Ended December 31, 2011:					
Intrastate transportation and storage	$12	$41	$53	$3	$56
Interstate transportation and storage	177	30	207	32	239
Midstream	809	28	837	(46)	791
NGL transportation and services	317	8	325	(81)	244
All other (including eliminations)	35	27	62	(1)	61
Total	$1,350	$134	$1,484	$(93)	$1,391

(1) Amounts reflected above for the midstream segment include growth and maintenance capital expenditures of $95 million and $10 million, respectively, incurred by Southern Union's gathering and processing operations prior to deconsolidation on April 30, 2013.
(2) We received $147 million in capital contributions from Regency related to their 30% share of Lone Star.

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 as a result of increases in the number of Common Units outstanding.

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Following is a summary of financing activities by period:

Year Ended December 31, 2013

Cash provided by financing activities was $325 million in 2013. We received $1.61 billion in net proceeds from Common Unit offerings. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, and acquisitions, as well as for general partnership purposes. In 2013, we had a net increase in our debt level of $819 million primarily due to ETP's issuance of $1.25 billion and $1.50 billion in aggregate principal amount of senior notes in January 2013 and September 2013, respectively, and Sunoco Logistics' issuance of $700 million in aggregate principal amount of senior notes in January 2013 (see Note 6 to our consolidated financial statements) partially offset by repayments of long-term debt and credit facilities of $2.71 billion in the aggregate. In connection with the issuance of senior notes, we incurred debt issuance costs of $32 million. In 2013, we paid distributions of $1.80 billion to our partners and we paid distributions of $382 million to noncontrolling interests. In addition, we received capital contributions of $147 million from Regency for its noncontrolling interest in Lone Star.

Year Ended December 31, 2012

Cash provided by financing activities was $1.29 billion in 2012. We received $791 million in net proceeds from Common Unit offerings. 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 2012, we had a net increase in our debt level of $1.78 billion primarily due to our issuance of $2.00 billion in aggregate principal amount of senior notes in January 2012 to fund the Citrus Acquisition, partially offset by the repurchase of $750 million in aggregate principal amount of senior notes in connection with our tender offers announced in January 2012. In connection with the issuance of senior notes in January 2012, we incurred debt issuance costs of $18 million. In 2012, we paid distributions of $1.34 billion to our partners. In addition, we received capital contributions of $320 million from Regency for its noncontrolling interest in Lone Star.

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 million under our equity distribution program. 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 million of capital contributions from Regency for its noncontrolling interest related to the LDH Acquisition. In 2011, we paid distributions of $1.16 billion to our partners.

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Description of Indebtedness

Our outstanding consolidated indebtedness at December 31, 2013 and 2012 was as follows:

	December 31,	
	2013	2012
ETP Senior Notes	$11,182	$7,692
Transwestern Senior Unsecured Notes	870	870
Southern Union Senior Notes	169	1,260
Panhandle Senior Notes	916	1,621
Sunoco Senior Notes	965	965
Sunoco Logistics Senior Notes	2,150	1,450
Revolving credit facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Note Payable to ETE	—	166
Other long-term debt	228	32
Unamortized premiums, net of discounts and fair value adjustments	308	417
Total debt	17,088	16,217
Less: current maturities	637	609
Long-term debt, less current maturities	$16,451	$15,608

The terms of our consolidated indebtedness and that of our subsidiaries are described in more detail below and in Note 6 to our consolidated financial statements.

January 2013 Senior Notes Offerings

In January 2013, ETP issued $800 million aggregate principal amount of 3.6% Senior Notes due February 2023 and $450 million aggregate principal amount of 5.15% Senior Notes due February 2043. ETP used the net proceeds of $1.24 billion from the offering to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

In January 2013, Sunoco Logistics issued $350 million aggregate principal amount of 3.45% Senior Notes due January 2023 and $350 million aggregate principal amount of 4.95% Senior Notes due January 2043. Sunoco Logistics' used the net proceeds of $691 million from the offering to repay borrowings outstanding under the Sunoco Logistics' Credit Facilities and for general partnership purposes.

September 2013 Senior Notes Offering

In September 2013, ETP issued $700 million aggregate principal amount of 4.15% Senior Notes due October 2020, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $450 million aggregate principal amount of 5.95% Senior Notes due October 2043. ETP used the net proceeds of $1.47 billion from the offering to repay $455 million in borrowings outstanding under the term loan of Panhandle's wholly-owned subsidiary, Trunkline LNG Holdings, LLC, to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction,

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Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. 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.

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.

In November 2013, we amended the ETP Credit Facility to, among other things, (i) extend the maturity date for one additional year to October 2017, (ii) remove the restriction prohibiting unrestricted subsidiaries from owning debt or equity interests in ETP or any restricted subsidiaries of ETP, (iii) amend the covenant limiting fundamental changes to remove the restrictions on mergers or other consolidations of restricted subsidiaries of ETP and to permit ETP to merge with another person and not be the surviving entity provided certain requirements are met, and (iv) amend certain other provisions more specifically set forth in the amendment.

As of December 31, 2013, the ETP Credit Facility had $65 million outstanding, and the amount available for future borrowings was $2.34 billion after taking into account letters of credit of $93 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 1.67%.

Southern Union Credit Facility

Proceeds from the SUGS Contribution were used to repay borrowings under the Southern Union Credit Facility and the facility was terminated.

Sunoco Logistics Credit Facilities

In November 2013, Sunoco Logistics replaced its existing $350 million and $200 million unsecured credit facilities with a new $1.50 billion unsecured credit facility (the "$1.50 billion Credit Facility"). The $1.50 billion Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions. Outstanding borrowings under the $350 million and $200 million credit facilities of $119 million at December 31, 2012 were repaid during the first quarter of 2013.

The $1.50 billion Credit Facility, which matures in November 2018, is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The $1.50 billion Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. Outstanding borrowings under this credit facility were $200 million at December 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility which expires in April 2015. The facility is available to fund West Texas Gulf's general corporate purposes including working capital and capital expenditures. Outstanding borrowings under this credit facility were $35 million at December 31, 2013.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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.

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

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; 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, 2013.

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."

Covenants Related to Southern Union

Southern Union is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Southern Union's lending agreements. Financial covenants exist in certain of Southern Union's debt agreements that require Southern Union to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. A failure by Southern Union to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if Southern Union did not cure such default within any permitted cure period or if Southern Union did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Southern Union's restrictive covenants include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of Southern Union's debt and other financial obligations and that of its subsidiaries.

In addition, Southern Union and/or its subsidiaries are subject to certain additional restrictions and covenants. These restrictions and covenants include limitations on additional debt at some of its subsidiaries; limitations on the use of proceeds from borrowing at some of its subsidiaries; limitations, in some cases, on transactions with its affiliates; limitations on the incurrence of liens; potential limitations on the abilities of some of its subsidiaries to declare and pay dividends and potential limitations on some of its subsidiaries to participate in Southern Union's cash management program; and limitations on Southern Union's ability to prepay debt.

Covenants Related to Sunoco Logistics

Sunoco Logistics' $1.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1

during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

The $35 million credit facility limits West Texas Gulf, on a rolling four-quarter basis, to a minimum fixed charge coverage ratio, as defined in the underlying credit agreement. The ratio for the fiscal quarter ending December 31, 2013 shall not be less than 1.00 to 1. The minimum ratio fluctuates between 0.80 to 1 and 1.00 to 1 throughout the term of the revolver as specified in the credit agreement. In addition, the credit facility limits West Texas Gulf to a maximum leverage ratio of 2.00 to 1. West Texas Gulf's fixed charge coverage ratio and leverage ratio were 1.12 to 1 and 0.88 to 1, respectively, at December 31, 2013.

Contingent Residual Support Agreement – AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6 of our consolidated financial statements, 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 contribution of the Propane Business, ETP entered into 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.

PEPL Holdings Guarantee of Collection

In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the "Regency Debt"), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. In connection with the closing of the SUGS Contribution on April 30, 2013, Regency entered into an agreement with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2013:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$16,780	$812	$1,422	$2,425	$12,121
Interest on long-term debt(1)	13,706	973	1,762	1,582	9,389
Payments on derivatives	74	35	39	—	—
Purchase commitments(2)	25,512	12,197	7,883	2,175	3,257
Transportation, natural gas storage and fractionation contracts	122	33	48	37	4
Operating lease obligations	767	80	148	119	420
Other	246	77	89	56	24
Total(3)	$57,207	$14,207	$11,391	$6,394	$25,215

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2013. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2013. 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.

(2) 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 refined product 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

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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, 2013 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. Approximately $5.72 billion of total purchase commitments relate to production from PES.

(3) Excludes non-current deferred tax liabilities of $3.76 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by ETP

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	Rate
Year Ended December 31, 2013	November 4, 2013	November 14, 2013	$0.90500
	August 5, 2013	August 14, 2013	0.89375
	May 6, 2013	May 15, 2013	0.89375
	February 7, 2013	February 14, 2013	0.89375
Year Ended December 31, 2012	November 6, 2012	November 14, 2012	$0.89375
	August 6, 2012	August 14, 2012	0.89375
	May 4, 2012	May 15, 2012	0.89375
	February 7, 2012	February 14, 2012	0.89375
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

On January 28, 2014, we declared a cash distribution for the three months ended December 31, 2013 of $0.9200 per Common Unit, or $3.68 annualized. We paid this distribution on February 14, 2014 to Unitholders of record at the close of business on February 7, 2014.

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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):

	Years Ended December 31,		
	2013	2012	2011
Distributions to the partners of ETP:			
Limited Partners:			
Common units held by public	$1,005	$783	$582
Common units held by ETE	268	180	180
Class H Units held by ETE Holdings	105	—	—
General Partner interest held by ETE	20	20	20
IDRs held by ETE	701	529	422
IDR relinquishments related to previous transactions	(199)	(90)	—
Total distributions to the partners of ETP	$1,900	$1,422	$1,204

The distributions reflected above for the year ended December 31, 2013 reflect IDR reductions totaling $199 million, which includes four quarters of IDR relinquishment related to the Citrus Merger, four quarters of IDR relinquishment related to the Holdco Transaction and two quarters of IDR relinquishment related to the Holdco Acquisition. The distributions reflected above for the year ended December 31, 2012 reflect IDR reductions totaling $90 million, which includes four quarters of IDR relinquishment related to the Citrus Merger and two quarters of IDR relinquishment related to the Holdco Transaction.

Following are incentive distributions ETE has agreed to relinquish to ETP:

- In conjunction with the Partnership's Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.
- As discussed in Note 3, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.

As discussed in Note 7 to our consolidated financial statements, ETP has agreed to make incremental cash distributions in the aggregate amount of $329 million to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017, in respect of the Class H units as a means to offset prior IDR subsidies that ETE agreed to in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition.

In addition to the amounts above, in connection with the Partnership's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of incentive distributions of $50 million, $50 million, $45 million and $35 million for the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

Following is a summary of the net amounts by which these incentive distribution relinquishments and incremental distributions on Class H Units would reduce the total distributions that would potentially be made to ETE in future quarters:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$26.5	$26.5	$26.5	$26.5	$106.0
2015	12.5	12.5	13.0	13.0	51.0
2016	18.0	18.0	18.0	18.0	72.0
2017	12.5	12.5	12.5	12.5	50.0
2018	11.25	11.25	11.25	11.25	45.0

2019	8.75	8.75	8.75	8.75	35.0

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Cash Distributions Paid by Sunoco Logistics

Sunoco Logistics is required by its partnership agreement to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by its general partner.

Following are distributions declared and/or paid by Sunoco Logistics:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2013	November 8, 2013	November 14, 2013	$0.63000
June 30, 2013	August 8, 2013	August 14, 2013	0.60000
March 31, 2013	May 9, 2013	May 15, 2013	0.57250
December 31, 2012	February 8, 2013	February 14, 2013	0.54500

On January 29, 2014, Sunoco Logistics declared a cash distribution for the three months ended December 31, 2013 of $0.6625 per common unit, or $2.65 annualized. Sunoco Logistics paid this distribution on February 14, 2014 to unitholders of record at the close of business on February 10, 2014.

The total amounts of Sunoco Logistics distributions declared during the period presented were as follows (all from Available Cash from Sunoco Logistics' operating surplus and are shown in the period with respect to which they relate):

	Year Ended December 31, 2013
Limited Partners	$255
General Partner interest	4
Incentive distributions	118
Total distributions declared	$377

On January 24, 2013, Sunoco Logistics declared a cash distribution for the three months ended December 31, 2012 of $0.5450 per common unit, or $2.18 annualized. The $80 million distribution, including $23 million to the general partner, was paid on February 14, 2013 to unitholders of record at the close of business on February 8, 2013.

New Accounting Standards

None.

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, 2013 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.

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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 and storage 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 our 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.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

Our retail marketing segment sells gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. In addition, some of Sunoco's retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.

Regulatory Assets and Liabilities. Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Accounting for Derivative Instruments and Hedging Activities. We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and refined products. These contracts consist primarily of futures and swaps. In addition, prior to the contribution of our retail propane activities to AmeriGas, we used derivatives to limit our exposure to propane market prices.

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

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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 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.

Impairment of Long-Lived Assets and Goodwill. Long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Goodwill and intangibles with indefinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value.

In order to test for recoverability 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, 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 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.

During the fourth quarter of 2013, we performed a goodwill impairment test on our Trunkline LNG reporting unit. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG’s Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount. We then applied the second step in the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The assets and liabilities of the reporting unit had recently been measured at fair value in 2012 as a result of the acquisition of Southern Union, and those estimated fair values had been recorded at the reporting unit through the application of “push-down” accounting. For purposes of the hypothetical purchase price allocation used in the goodwill impairment test, we estimated the fair value of the assets and liabilities of the reporting unit in a manner similar to the original purchase price allocation. In allocating value to the property, plant and equipment, we used current replacement costs adjusted for assumed depreciation. We also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. We adjusted deferred income taxes based on these estimated fair values. Based on this hypothetical purchase price allocation, estimated goodwill was $184 million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, we recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

No other goodwill impairments were identified or recorded for our reporting units.

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 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 1 to 99 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. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. We will record an asset retirement obligation in the periods in which management can reasonably estimate the settlement dates.

Except for the AROs of Southern Union, Sunoco Logistics and Sunoco discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2013 and 2012 because the settlement dates were indeterminable. Although a number of other onshore assets in Southern Union's system are subject to agreements or regulations that give rise to an ARO upon Southern Union's discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement. Sunoco has legal asset retirement obligations for several other assets at its refineries, pipelines and terminals, for which it is not possible to estimate when the obligations will be settled. Consequently, the retirement obligations for these assets cannot be measured at this time. At the end of the useful life of these underlying assets, Sunoco is legally or contractually required to abandon in place or remove the asset. Sunoco Logistics believes it may have additional asset retirement obligations related to its pipeline assets and storage tanks, for which it is not possible to estimate whether or when the retirement obligations will be settled. Consequently, these retirement obligations cannot be measured at this time.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

As of December 31, 2013, there were no legally restricted funds for the purpose of settling AROs.

Pensions and Other Postretirement Benefit Plans

We are required to measure plan assets and benefit obligations as of its fiscal year-end balance sheet date. We recognize the changes in the funded status of our defined benefit postretirement plans through AOCI or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

The calculation of the net periodic benefit cost and benefit obligation requires the use of a number of assumptions. Changes in these assumptions can have a significant effect on the amounts reported in the financial statements. The Partnership believes that the two most critical assumptions are the assumed discount rate and the expected rate of return on plan assets.

The discount rate is established by using a hypothetical portfolio of high-quality debt instruments that would provide the necessary cash flows to pay the benefits when due. Net periodic benefit cost and benefit obligation increases and equity correspondingly decreases as the discount rate is reduced.

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The expected rate of return on plan assets is based on long-term expectations given current investment objectives and historical results. Net periodic benefit cost increases as the expected rate of return on plan assets is correspondingly reduced.

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

For more information on our litigation and contingencies, see Note 10 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" in this report.

Environmental Remediation Activities. The Partnership's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual for known claims is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities.

Losses attributable to unasserted claims are generally reflected in the accruals on an undiscounted basis, to the extent they are probable of occurrence and reasonably estimable. We have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. The Partnership's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded.

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (i.e., less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2013, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $6 million. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets and, in many cases, reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.

Total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership’s liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years. Management believes that the Partnership’s exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such charges would have a material adverse impact on the Partnership’s consolidated financial position.

Deferred Income Taxes. ETP recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards (“NOLs”) and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal tax alternative minimum tax credit carryforwards totaling $217 million have been included in ETP's consolidated balance sheet as of December 31, 2013. All of the deferred income tax assets attributable to state and federal NOL benefits expire before 2032 as more fully described below. The state NOL carryforward benefits of $101 million (net of federal benefit) begin to expire in 2013 with a substantial portion expiring between 2029 and 2032. The federal NOLs of $216 million ($76 million in benefits) will expire in 2032, while the $40 million of the federal tax alternative minimum tax credit carryforwards have no expiration date. We have determined that a valuation allowance totaling $74 million (net of federal income tax effects) is required for the state NOLs at December 31, 2013 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

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;
- 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;

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- 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.

Inflation

Interest rates on existing and future credit facilities and future debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and has not had a material effect on our results of operations. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by commodity price changes. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along a portion of increased costs to our customers in the form of higher fees.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For certain of our activities, we are exposed to market risks related to the volatility of commodity 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,

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and location price differentials related to the transportation of natural gas. Additionally, we use derivatives for trading purposes in this segment.

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We also use derivative swap contracts to mitigate risk from price fluctuations on NGLs we retain for fees in our midstream segment.
- Sunoco Logistics uses derivative contracts as economic hedges against price changes related to its forecasted refined products and NGL purchase and sale activities.
- In our all other segment, we utilized derivatives for trading purposes.

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. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Sunoco Logistics manages exposures to crude oil, refined products and NGL commodity prices by monitoring inventory levels and expectations of future commodity prices when making decisions with respect to risk management and inventory carried. Sunoco Logistics' policy is to purchase only commodity products for which it has a market and to structure its sales contracts so that price fluctuations for those products do not materially affect the margin Sunoco Logistics receives. Sunoco Logistics also seeks to maintain a position that is substantially balanced within its various commodity purchase and sale activities. Sunoco Logistics may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances, as well as logistical issues associated with inclement weather conditions. When unscheduled inventory builds or draws do occur, they are monitored and managed to a balanced position over a reasonable period of time.

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The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, 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, thousand megawatt for power and barrels for natural gas liquids and refined products. Dollar amounts are presented in millions.

	December 31, 2013			December 31, 2012		
	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						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	9,457,500	$3	$5	—	$—	$—
Basis Swaps IFERC/NYMEX(1)	(487,500)	1	—	(30,980,000)	(6)	—
Swing Swaps	1,937,500	1	—	—	—	—
Power (Megawatt):						
Forwards	351,050	1	1	19,650	—	1
Futures	(772,476)	—	2	(1,509,300)	(1)	1
Options – Puts	(52,800)	—	—	—	—	—
Options – Calls	103,200	—	—	1,656,400	2	1
Crude (Bbls) – Futures	103,000	—	1	—	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	570,000	—	—	150,000	(1)	—
Swing Swaps IFERC	(9,690,000)	1	—	(83,292,500)	1	1
Fixed Swaps/Futures	(8,195,000)	13	3	27,077,500	(7)	9
Forward Physical Contracts	5,668,559	(1)	2	11,689,855	—	2
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	—	3	(30,000)	—	—
Refined Products (Bbls) – Futures	(1,133,600)	—	17	(666,000)	(3)	14
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(7,352,500)	—	—	(18,655,000)	(1)	—
Fixed Swaps/Futures	(50,530,000)	(11)	23	(44,272,500)	4	15
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(1,825,000)	—	—	—	—	—
Fixed Swaps/Futures	(12,775,000)	(3)	6	(8,212,500)	(3)	3
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	(1)	4	(930,000)	(2)	7
Refined Products (Bbls) – Futures	—	—	—	(98,000)	—	1
Crude (Bbls) – Futures	(30,000)	—	—	—	—	—

(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

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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, 2013, we had $907 million of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $9 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.

The following table summarizes our interest rate swaps outstanding (dollars in millions), none of which are designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type(1)	December 31, 2013	December 31, 2012
ETP	July 2013(2)	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$—	$400
ETP	July 2014(2)	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union(3)	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union(3)	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

(1) 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. During the year ended December 31, 2013, we settled $400 million of ETP's forward-starting interest rate swaps that had an effective date of July 2013.

(3) In connection with the Panhandle Merger, Southern Union's interest rate swaps outstanding were assumed by Panhandle.

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 interest rate derivatives) of $29 million as of December 31, 2013. For the $1.4 billion 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 of $14 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. For Southern Union's fixed to floating interest rate swaps, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $3 million.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheets 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 ETP LLC, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2013.

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 ETP LLC, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 1992 Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2013.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2013, 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 the internal control over financial reporting of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013, based on criteria established in the 1992 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 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 financial statements of the Partnership as of and for the year ended December 31, 2013, and our report dated February 27, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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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, 2013 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, which we refer to in this Item as "our General Partner." 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. As of December 31, 2013, our Board of Directors was comprised of seven persons, four of whom qualified as "independent" under the NYSE's corporate governance standards. Our Board of Directors has determined that Messrs. Collins, Glaske, Grimm, and Skidmore all meet the NYSE's independence requirements. Our current directors who are not independent consist of Kelcy L. Warren, ETP LLC's Chief Executive Officer, and Marshall S. McCrea III, ETP LLC's President and Chief Operating Officer, as well as Jamie Welch, the Group Chief Financial Officer of ETE's general partner.

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 specifically 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 2013, 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. Pursuant to the terms of our partnership agreement, 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. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in Item 1A. Risk Factors in this annual report).

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 David K. Skidmore qualified as Audit Committee financial experts during 2013. A description of the qualifications of Mr. Glaske and Mr. Skidmore 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 David K. Skidmore 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 David K. Skidmore serve as the members of the Compensation Committee and Mr. Grimm serves as the chairman of the Compensation Committee. Our Board of Directors has determined that both Messrs. Grimm and Skidmore 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 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 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.

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.

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Directors and Executive Officers of Our 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 27, 2014. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	58	Chief Executive Officer and Chairman of the Board of Directors
Marshall S. (Mackie) McCrea, III	54	President, Chief Operating Officer and Director
Martin Salinas, Jr.	42	Chief Financial Officer
Jamie Welch	47	Director and ETE Group Chief Financial Officer and Head of Business Development
Thomas P. Mason	57	Senior Vice President, General Counsel and Secretary
Richard Cargile	54	President of Midstream Operations
Paul E. Glaske	80	Director
Ted Collins, Jr.	75	Director
Michael K. Grimm	59	Director
David K. Skidmore	58	Director

Messrs. Warren, McCrea and Welch also serve as directors of ETE's 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 and of Sunoco Logistics. 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. Mr. Salinas earned his B.B.A. in Accounting from the University of Texas at San Antonio in 1994 and is a Certified Public Accountant. Mr. Salinas also serves on the Board of Directors of the general partner of Sunoco Logistics.

Jamie Welch. Mr. Welch is the Group Chief Financial Officer and Head of Business Developments for the Energy Transfer family since June 2013. Mr. Welch has also served on the Board of Directors of ETE, ETP, and Sunoco

Logistics since June 2013. Before joining ETE, Mr. Welch was Head of the EMEA Investment Banking Department and Head of the Global Energy Group at Credit Suisse. He was also a member of the IBD Global Management Committee and the EMEA Operating Committee. Mr. Welch joined Credit Suisse First Boston in 1997 from Lehman Brothers Inc. in New York, where he was a Senior Vice President in the global utilities & project finance group. Prior to that he was an attorney with Milbank, Tweed, Hadley & McCloy (New York) and a barrister and solicitor with Minter Ellison in Melbourne, Australia. The members of our General Partner selected Mr. Welch to serve on the Board of Directors because of his understanding of energy-related corporate finance gained through his experience in the investment banking and legal fields.

Thomas P. Mason. Mr. Mason has served as Senior Vice President, General Counsel and Secretary of our General Partner since April 2012. Mr. Mason previously served as Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary of our General Partner from 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. Mr. Mason also serves on the Board of Directors of the general partner of Sunoco Logistics.

Richard Cargile. Mr. Cargile joined ETP in March 2012 and serves as President of Midstream Operations. Mr. Cargile joined ETP with over 30 years of midstream experience. Mr. Cargile joined Phillips Petroleum Company in 1982 as a project development engineer. He worked in various capacities in the gas and gas liquids group of Phillips Petroleum Company, Phillips 66 Natural Gas Company and GPM Gas Corporation. He was named vice president of East Permian Commercial in 2000 when GPM Gas Corporation merged with DCP Midstream, LLC (“DCP”). In 2003, he rose to Southern Division Vice President where he was responsible for DCP’s Permian and Gulf Coast business units and appointed to DCP’s Executive Committee. In 2007, he was promoted to Group Vice President of commercial and business development, and in 2008 he was named Group Vice President of EHS, operations, and technical services. In 2009, he was appointed to president of DCP’s southern business unit, where his responsibilities included executive management of commercial and operations of assets in the west and east regions, and was responsible for corporate engineering, technical services, measurement and reliability.

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 opportunities.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. He also serves as a Director to both Oasis Petroleum Corp. and CLL Global Research Foundation. He has also served on both the Audit Committee and Nominating and Governance Committee for Oasis Petroleum Corp. since May of 2011. Mr. Collins previously served as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988 Mr. Collins was President of Enron Oil & Gas Co. and its predecessors, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quasar Petroleum Company. 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 properties.

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 served as its President and Chief Executive Officer from 1995 until 2006 when it was sold. Currently, Mr. Grimm is President of Rising Star Energy Development Company, Rising Star Petroleum, LLC and is Chairman of the Board 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. He has a B.B.A. from the University of Texas at Austin. 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.

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David K. Skidmore. Mr. Skidmore has served as a director of our General Partner since March 2013. He has been Vice President of Ventex Oil & Gas, Inc. since 1995 and has been actively involved in exploration and production throughout the Gulf Coast and mid-Continent regions for over 35 years. He founded Skidmore Exploration, Inc. in 1981 and has been an independent oil and gas producer since that time. From 1977 to 1981, he worked for Paraffine Oil Corporation and Texas Oil & Gas in Houston. He holds BS degrees in both Geology and Petroleum Engineering, is a Certified Petroleum Geologist and Registered Professional Engineer, and active member of the AAPG, and SPE. Mr. Skidmore is a member of both the Audit Committee and Compensation Committee. The Board selected Mr. Skidmore to serve as a director because of his continual involvement in geological, geophysical, legal, engineering and accounting aspects of an active oil and gas exploration and production company. As an energy professional, active oil and gas producer and successful business owner, Mr. Skidmore possesses valuable first-hand knowledge of the energy transportation business and market conditions affecting its economics.

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. Our employees are employed by our Operating Companies, and thus, our General Partner does not incur additional reimbursable costs.

Our General Partner is ultimately controlled by the general partner of ETE, which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our Partnership Agreement with respect to its ownership of a general partner interest and the incentive distribution rights specified in our Partnership Agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our Partnership Agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner’s executive officers. Our General Partner’s distribution rights are described in detail in Note 7 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

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, 2013, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, with the exception of a late filing of a Form 4 transaction by Mr. Warren.

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, 2013, ETE owned 100% of our General Partner, approximately 14.8% of our outstanding Common Units and 100% of our outstanding Class H Units. All of our employees are employed by and receive employee benefits from our Operating Companies.

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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, Senior Vice President, General Counsel and Secretary; and
- Richard Cargile, President of Midstream Operations.

Our General Partner's Philosophy for Compensation of Executives
In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based or "at-risk" compensation and that executives' total compensation levels should be very competitive in the marketplace for executive talent and abilities. Our General Partner seeks a total compensation program that provides for a slightly below the median market annual base compensation rate but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market.
Our General Partner believes the incentive-based 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 the achievement of the annual financial performance objectives and (ii) the annual grant of restricted unit awards under our equity incentive plan(s), which awards are intended to provide a longer term incentive and retention value 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.
Prior to December 2012, our equity awards were primarily 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. Beginning in December 2012, we began granting restricted unit awards that vest, based upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. 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, 2013, 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.
Compensation Philosophy
Our compensation program is structured to provide the following benefits:

- reward executives with an industry-competitive total compensation package of competitive base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;

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- 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 or "at-risk" compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2013, 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;
- time-vested restricted unit awards under the equity incentive plan(s);
- payment of distribution equivalent rights ("DERs") on unvested time-based restricted unit awards under our equity incentive plan;
- vesting of previously issued time-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 employer 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 our 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 (US) Inc. ("Mercer") during the year ended December 31, 2013 to both (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including our named executive officers; (ii) assist in the determination of appropriate compensation levels for our senior management, including the named executive officers; and (iii) to confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy. This review by Mercer was deemed necessary given the series of transforming transactions we have completed over the past few years, which have significantly increased our size and scale from both a financial and asset perspective.

In conducting its review, Mercer worked with us to identify a "peer group" of 15 leading companies in the energy industry that most closely reflect our profile in terms of revenues, assets and market value as well as compete with us for talent at the senior management level. The identified companies were:

- Conoco Phillips
- Enterprise Products Partners, L.P.
- Plains All American Pipeline, L.P.
- Halliburton Company
- National Oilwell Varco, Inc.
- Baker Hughes Incorporated
- Apache Corp.
- Marathon Oil Corporation
- Anadarko Petroleum
- ONEOK Partners, L.P.
- EOG Resources, Inc.
- Kinder Morgan Energy Partners, L.P.
- The Williams Companies, Inc.
- Enbridge Energy Partners, L.P.
- DCP Midstream Partners, L.P.

The compensation analysis provided by Mercer covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives of these companies. The Compensation Committee utilized the information provided by Mercer to compare the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at these other companies with those of our named executive officers to ensure that compensation of our named executive officers is both consistent with our compensation philosophy and competitive with the compensation for executive officers of these other companies. The Compensation Committee considered and reviewed the results of the study performed by Mercer to ensure the results indicated that our compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives. The Compensation Committee also specifically evaluated benchmarked results for the annual base salary, annual short-term cash bonus or long-term equity incentive awards of the named executive officers to the compensation levels at the identified "peer group" companies. Mercer did not provide any non-executive compensation services for the Partnership during 2013.

Base Salary. As discussed above, the base salaries of our named executive officers are targeted to yield an annual base salary slightly below the median level of market and are determined by the Compensation Committee after taking into account the recommendations of Mr. Warren. For 2013, the Compensation Committee approved an increase of 6.7% to Mr. McCrea's annual base salary, 5.9% to Mr. Salinas' annual base salary, and 10% to Mr. Mason's annual base salary. The Compensation Committee determined that such increases were warranted based on the results of the Mercer study and the factors described below under "Annual Bonus." The Compensation Committee also deemed the increases to be reasonable in light of the expanded roles that each of the individuals serves with respect to the consolidated organization subsequent to the Citrus, Sunoco and Holdco Transactions in 2012 and the associated increased in role and responsibility of each named executive office in light of the same.

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 140% of their annual bonus target. For 2013, the Compensation Committee approved a short-term annual cash bonus target for Mr. McCrea of 140% of his annual base salary, 120% of his annual base salary for Mr. Salinas, 125% of his annual base salary for Mr. Mason and 100% of his annual base salary for Mr. Cargile. In the cases of Messrs. McCrea, Salinas and Mason their annual bonus target was increased to its new level from a target of 100% of annual base salary consistent with the results of the Mercer study, while Mr. Cargile's target remained at its 2012 level of 100% of annual base salary. In February 2014, the Compensation Committee approved cash bonuses relating to the 2013 calendar year to Messrs. McCrea, Salinas, Mason and Cargile of $1,080,961, $524,423, $646,635 and $305,000, respectively. 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, (iii) the completion of mergers, acquisitions or similar transactions that are expected to be accretive to the Partnership and increase distributable cash flow, (iv) the overall management of the Partnership's business, and (v) the individual performances of these individuals with respect to promoting the Partnership's financial, strategic and operating objectives for 2013. The cash bonuses awarded to each of the executive officers for 2013 were consistent with the target.

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, phantom 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 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 that are subject to vesting over a specified time period. Upon vesting of any unit award, ETP Common Units are issued.

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In consideration of the results of the Mercer study for 2013, the Compensation Committee approved increased long-term incentive awards targets for certain of the named executive officers. Mr. McCrea's long-term incentive target increased from 330% of his annual base salary to 700% of his base salary, Mr. Salinas' annual long-term incentive target increased from 250% of his annual base salary to 300%, Mr. Mason's annual long-term incentive target increased from 270% of his annual base salary to 400% and Mr. Cargile's target remained at 150% of annual base salary. In December 2013, the Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas, Mason and Cargile of 69,375 units, 16,724 units, 40,923 units and 9,500 units, respectively. These unit awards provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, subject to continued employment through each specified vesting date. As described below in the section titled Subsidiary Equity Awards, for 2013, in discussions between the Compensation Committee and the CEO as well as the compensation committee of the general partner of Sunoco Logistics, it was determined that approximately 33% of the total long-term incentive award target values of Messrs. McCrea and Salinas would be composed of restricted units awarded under Sunoco Logistics' equity incentive plan in considerations for their roles and responsibilities at Sunoco Logistics in addition to the Partnership. At Sunoco Logistics, Mr. McCrea serves as Chairman of the Board of Sunoco Logistics' general partner and Mr. Salinas serves as a member of the board and Chief Financial Officer of Sunoco Logistics' general partner. It is expected that the long-term equity awards of Messrs. McCrea and Salinas will recognize a similar aggregation of restricted units being awarded under our equity incentive plan and Sunoco Logistics' equity incentive plan in future years. The terms and conditions of the restricted unit awards to Messrs. McCrea and Salinas under the Sunoco Logistics equity plan are identical to the terms and conditions of the restricted unit awards under our equity plan to Messrs. McCrea and Salinas.

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 DER cash payment 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.

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, provided however, the unvested awards will be accelerated in the event of a change in control of the Partnership or the death or disability of the award recipient prior to the applicable vesting period being satisfied. 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 to any named executive officers in 2013.

Unit Ownership Guidelines. In December 2013, the Board of Directors adopted the ETP Executive Unit Ownership Guidelines (the "Guidelines"), which set forth minimum ownership guidelines applicable to certain executives of the Partnership with respect to Common Units representing limited partnership interests in the Partnership. The applicable unit ownership guidelines are denominated as a multiple of base salary, and the amount of Common Units required to be owned increases with the level of responsibility. Under these guidelines, the President and Chief Operating Officer is expected to own Common Units having a minimum value of five times his base salary, while each of the remaining named executive officers (other than our CEO) are expected to own Common Units having a minimum value of four times their respective base salary. In addition to the named executive officers, these guidelines also apply to other covered executives, which executives are expected to own either directly or indirectly in accordance with the terms of the Guidelines Common Units having minimum values ranging from two to four times their respective base salary. The Guidelines do not apply to our CEO, who receives a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits.

Our General Partner and the Compensation Committee believe that the ownership of our Common Units, as reflected in the Guidelines, is an important means of tying the financial risks and rewards for our executives to our total unitholder return, aligning the interests of such executives with those of our Unitholders, and promoting the Partnership’s interest in good corporate governance.

Covered executives are generally required to achieve their ownership level within five years of becoming subject to the guidelines; however, certain covered executives, based on their tenure as an executive, are required to achieve compliance within two years of the December 2013 effective date of the Guidelines. Thus, compliance with the guidelines will be required for all of our current named executive officers beginning December 2015, except for Richard Cargile who joined ETP in March 2012.

Covered executives may satisfy the guidelines through direct ownership of Common Units or indirect ownership by certain immediate family members. Direct or indirect ownership of ETE common units shall count on a one to one ratio for purposes of satisfying minimum ownership requirements; however, unvested unit awards may not be used to satisfy the minimum ownership requirements.

Executive officers who have not yet met their respective guideline must retain and hold all Common Units (less Common Units sold to cover the executive's applicable taxes and withholding obligation) received in connection with long-term incentive awards. Once the required ownership level is achieved, ownership of the required Common Units must be maintained for as long as the covered executive is subject to the guidelines. However, those individuals who have met or exceeded their applicable ownership guideline may dispose of our Common Units in a manner consistent with applicable laws, rules and regulations, including regulations of the SEC and our internal policies, but only to the extent that such individual's remaining ownership of Common Units would continue to exceed the applicable ownership guideline.

Subsidiary Equity Awards. In addition to their roles as officers of our General Partner, Messrs. McCrea and Salinas also serve as officers and directors of the general partner of Sunoco Logistics. In connection with those roles at Sunoco Logistics' general partner, in December 2013, the compensation committee of Sunoco Logistics' general partner awarded Messrs. McCrea and Salinas time-based restricted units of Sunoco Logistics in the amount of 27,300 units and 6,550 units, respectively. The terms and conditions of the restricted unit awards to Messrs. McCrea and Salinas under the Sunoco Logistics equity plan are identical to the terms and conditions of the restricted unit awards under our equity plan to Messrs. McCrea and Salinas.

The previous annual grant of Sunoco Logistics equity awards occurred in January 2013, at which time Messrs. McCrea and Salinas were granted 16,667 units and 8,333 units, respectively. These awards are reflected as compensation in 2013 for Messrs. McCrea and Salinas in the "Compensation Tables" section below.

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 previously awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officers. These rights included the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the officer vested in the ETE units at a rate of 20% per year. As these ETE units conveyed to the recipients of the awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards were paid by ETE or ETP. We recognized 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. As of December 31, 2013, no such affiliate equity awards remained outstanding. During 2013, Messrs. McCrea and Salinas vested in rights related to ETE units of 84,000 and 96,000, respectively (after adjustment for ETE's two-for-one common unit split in January 2014).

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 amounts deferred by the participant and the amounts deferred by the Partnership are fully vested at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

Beginning in January 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with a base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

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 Termination or Change of Control” for additional information.

In addition, our General Partner has also adopted the ETP GP Severance Plan and Summary Plan Description effective as of June 12, 2013, (the “Severance Plan”), which provides for payment of certain severance benefits in the event of Qualifying Termination (as that term is defined in the Severance Plan). In general, the Severance Plan provides payment of two weeks of annual base salary for each year or partial year of employment service with the Partnership up to a maximum of fifty-two weeks or one year of annual base salary (with a minimum of four weeks of annual base salary) and up to three months of continued group health insurance coverage. The Severance Plan also provides that the Partnership may determine to pay benefits in addition to those provided under the Severance Plan based on special circumstances, which additional benefits shall be unique and non-

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precedent setting. The Severance Plan is available to all salaried employees on a nondiscriminatory basis; therefore, amounts that would be payable to our named executive officers upon a Qualified Termination have been excluded from "Compensation Tables – Potential Payments Upon a Termination or Change of Control" below.

Deferred Compensation Plan. We maintain a deferred compensation plan ("DC Plan"), which 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 elect to have their accounts distributed in one lump sum payment or in annual installments over a period of three or five years upon retirement, and in a lump sum upon other termination. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. 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 8 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm and Skidmore served on the Compensation Committee during 2013. During 2013, 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. Skidmore are former employees of ours or any of our subsidiaries.

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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
David K. Skidmore

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]	2013	$5,814	$—	$—	$—	$ —	$ —	$ —	$5,814
Chief Executive	2012	3,700	—	—	—	—	—	—	3,700
Officer	2011	3,240	—	—	—	—	—	—	3,240
Martin Salinas, Jr.	2013	437,019	524,423	1,861,698	—	—	56,036	26,136	2,905,312
Chief Financial	2012	392,750	375,000	755,515	—	—	23,261	26,140	1,572,666
Officer	2011	360,532	400,000	1,128,500	—	—	(6,462)	25,020	1,907,590
Marshall S. (Mackie) McCrea, III	2013	772,115	1,080,961	6,715,336	—	—	—	13,323	8,581,735
President and Chief	2012	690,000	700,000	1,510,985	—	—	—	12,802	2,913,787
Operating Officer	2011	615,049	750,000	9,542,520	—	—	—	12,972	10,920,541
Thomas P. Mason	2013	517,308	646,635	2,308,057	—	—	—	36,923	3,508,923
Senior Vice	2012	466,424	500,000	1,359,900	—	—	—	35,998	2,362,322
President, General Counsel and Secretary	2011	432,901	750,000	1,805,600	—	—	—	32,590	3,021,091
Richard Cargile	2013	331,250	305,000	535,800	—	—	83,943	13,323	1,269,316
President of Midstream Operations	2012	237,500	230,000	1,379,880	—	—	3,534	12,279	1,863,193

(1) The discretionary cash bonus amounts for our named executive officers for 2013 reflect cash bonuses approved by the Compensation Committee in February 2014 that are expected to be paid in March 2014.

(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 8 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2013 in this column include (i) matching contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $9,327 for Mr. Salinas and $12,750 each for Messrs. McCrea, Mason and Cargile, (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.

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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]
ETP Unit Awards:					
Kelcy L. Warren	N/A	—	—	$—	$—
Martin Salinas, Jr.	12/30/2013	16,724	—	—	943,234
Marshall S. (Mackie) McCrea, III	12/30/2013	69,375	—	—	3,912,750
Thomas P. Mason	12/30/2013	40,923	—	—	2,308,057
Richard Cargile	12/30/2013	9,500	—	—	535,800
Sunoco Logistics Unit Awards:					
Martin Salinas, Jr.	12/05/2013	6,550	—	—	445,400
	1/24/2013	8,333	—	—	473,064
Marshall S. (Mackie) McCrea, III	12/05/2013	27,300	—	—	1,856,400
	1/24/2013	16,667	—	—	946,186

(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 8 to our consolidated financial statements.

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

Name	Grant Date[1]	Unit Awards 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] ($)
ETP Unit Awards:			
Kelcy L. Warren	N/A	—	$—
Martin Salinas, Jr.	12/30/2013	16,724	957,449
	1/10/2013	16,667	954,186
	12/20/2011	15,000	858,750
	12/15/2010	8,000	458,000
	12/15/2009	3,837	219,668
Marshall S. (Mackie) McCrea, III	12/30/2013	69,375	3,971,719
	1/10/2013	33,333	1,908,314
	12/20/2011	30,000	1,717,500
	5/2/2011	54,400	3,114,400
	1/14/2011	100,000	5,725,000
	12/15/2009	4,000	229,000
Thomas P. Mason	12/30/2013	40,923	2,342,842
	1/10/2013	30,000	1,717,500
	12/20/2011	24,000	1,374,000
	12/15/2010	8,000	458,000
	12/15/2009	3,637	208,218
Richard Cargile	12/30/2013	9,500	543,875
	1/10/2013	12,000	687,000
	3/14/2012	10,800	618,300
Sunoco Logistics Unit Awards:			
Martin Salinas, Jr.	12/5/2013	6,550	494,394
	1/24/2013	6,666	503,150
Marshall S. (Mackie) McCrea, III	12/5/2013	27,300	2,060,604
	1/24/2013	13,333	1,006,375

(1) ETP Common Unit awards outstanding to Messrs. Salinas, McCrea, Mason and Cargile vest as follows:

- at a rate of 60% in December 2016 and 40% in December 2018 for awards granted in December 2013;
- at a rate of 60% in December 2015 and 40% in December 2017 for awards granted in January 2013;
- ratably in December of each year through 2016 for awards granted in December 2011 and March 2012;
- ratably in December of each year through 2015 for awards granted in December 2010, January 2011 and May 2011; and
- in December 2014 for awards granted in December 2009.

Sunoco Logistics common unit awards outstanding to Messrs. Salinas and McCrea vest as follows:

- ratably in December of each year through 2018 for awards granted in December 2013; and
- ratably in December of each year through 2017 for awards granted in January 2013.

(2) Market value was computed as the number of unvested awards as of December 31, 2013 multiplied by the closing price of our Common Units or Sunoco Logistics common units, accordingly, on December 31, 2013.

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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) ($)
ETP Unit Awards:		
Kelcy L. Warren	—	$—
Martin Salinas, Jr.	16,837	908,053
Marshall S. (Mackie) McCrea, III	95,200	5,134,326
Thomas P. Mason	29,637	1,577,493
Richard Cargile	3,600	194,155
Sunoco Logistics Unit Awards:		
Martin Salinas, Jr.	1,667	114,456
Marshall S. (Mackie) McCrea, III	3,334	228,912

(1) Amounts presented represent the number of unit awards vested during 2013 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 or Sunoco Logistics common units, accordingly, upon the vesting date.

We have not issued option awards.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY(1) ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY(1) ($)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE(1) ($)
Kelcy L. Warren	$—	$—	$—	$ —	$—
Martin Salinas, Jr.	44,610	—	56,036	—	303,495
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Richard Cargile	327,964	—	83,943	—	512,779

(1) The executive contributions and aggregate earnings reflected above for Messrs. Salinas and Cargile are included in total compensation in the "Summary Compensation Table"; the remainder of the aggregate balance at last fiscal year end was reported as compensation in previous fiscal years.

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, 2013, the fair value of the unvested awards granted pursuant to the 2004 Unit Plan as of December 31, 2013 was $458,000 for Mr. Mason. 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. 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% 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 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.

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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

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. In 2013, non-employee directors received an annual fee of $50,000 in cash. 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 2013, members of the Conflicts Committee received cash payments on a to-be-determined basis for each Conflicts Committee assignment. For their service on the Conflicts Committee during 2013, Messrs. Collins, Grimm and Skidmore each received additional compensation of $10,000. Employee directors, including Messrs. Warren, McCrea and Welch, do not receive any fees for service as directors. In addition, the non-employee directors participate in our 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. In 2014 and beyond, non-employee directors will receive annual grants of restricted ETP Common Units equal to an aggregate of $100,000 divided by the closing price of our Common Units on the date of grant. Beginning in 2013, ETP Common Units granted to non-employee directors will vest 60% after the third year and the remaining 40% after the fifth year after the grant date. Previously, vesting was ratable over three years.

The compensation paid to the non-employee directors of our General Partner in 2013 is reflected in the following table:

Name	Fees Paid in Cash[1] ($)	Unit Awards[2] ($)	All Other Compensation ($)	Total ($)
Bill W. Byrne[3]	$78,995	$75,143	$—	$154,138
Paul E. Glaske	81,683	75,143	—	156,826
Ted Collins, Jr.	85,833	75,143	—	160,976
Michael K. Grimm	121,792	75,143	—	196,935
David K. Skidmore[4]	63,826	117,750	—	181,576

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

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price of Common Units as of the grant date.

(3) Mr. Byrne resigned from the Board of Directors in August 2013.

(4) Mr. Skidmore was appointed to the Board of Directors in March 2013.

As of December 31, 2013, Messrs. Glaske, Collins and Grimm each had 2,352 unit awards outstanding and Mr. Skidmore had 2,500 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, 2013:

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	3,181,165	$—	915,922
Equity compensation plans not approved by security holders	—	—	—
Total	3,181,165	—	915,922

Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 18, 2014, 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	206,574	*	
	Martin Salinas, Jr.	45,326	*	
	Jamie Welch	20,000	*	
	Thomas P. Mason	92,692	*	
	Richard Cargile	9,287	*	
	Paul E. Glaske	98,578	*	
	Ted Collins, Jr.	99,739	*	
	Michael K. Grimm	22,877	*	
	David K. Skidmore	1,010	*	
	All Directors and Executive Officers as a Group (10 Persons)	617,190	*	
	ETE[(4)]	44,324,102	13.2	%
	ETE Holdings[(4)]	5,226,967	1.6	%
Class E Units	Heritage Holdings, Inc.[(5)]	8,853,832	100	%
Class G Units	Sunoco, Inc.[(6)]	90,706,000	100	%
Class H Units	ETE Holdings[(4)]	50,160,000	100	%

*Less than 1%

(1) The address for Messrs. Warren, Salinas, Welch, Mason, Cargile, Glaske, Collins, Grimm and Skidmore 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 and ETE Holdings is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Sunoco, Inc. is 1818 Market Street, Suite 1500, Philadelphia, Pennsylvania 19103.

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(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 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 0.01% 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.

(6) The Partnership indirectly owns 100% of the common stock of Sunoco, Inc.

In connection with the Parent Company Credit Agreement, ETE and certain of its subsidiaries entered into a Pledge and Security Agreement (the “Security Agreement”) with Credit Suisse AG, Cayman Islands Branch, as collateral agent (the “Collateral Agent”). The Security Agreement secures all of ETE’s obligations under the Parent Company Credit Agreement and grants to the Collateral Agent a continuing first priority lien on, and security interest in, all of ETE’s and the other grantors’ tangible and intangible assets.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For a discussion of director independence, see Item 10. “Directors, Executive Officers and Corporate Governance.”

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 contractually-limited 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 (see “Risks Related to Conflicts of Interest” in Item 1A. Risk Factors in this annual report).

ETE owns directly and indirectly the general partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights, 49.6 million ETP Common Units and 50.2 million Class H Units.

We have a shared services agreement in which we provide various general and administrative services for ETE. See discussion in Note 13 to our consolidated financial statements.

We have an operating lease agreement with the former owners of ETG, which we acquired in 2009. These former owners include Mr. Warren and Mr. Ray C. Davis, a former ETP board member. We pay these former owners $5 million in operating lease payments per year through 2017. 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.

We received $27 million, $18 million and $17 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, 2013, 2012 and 2011, respectively.

Immediately following the closing of the Partnership’s acquisition of Sunoco, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE’s contribution, the Partnership contributed its interest in Sunoco to Holdco and retained a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to the Partnership in exchange for 90.7 million Class F Units representing limited partner interests in the Partnership. The Class F Units were entitled to 35% of the quarterly cash distribution generated by the Partnership and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current level. In April 2013, all of the outstanding Class F Units were exchanged for Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss.

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis.

On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, which owns the general partner and IDRs of ETP, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the incentive distribution relinquishments previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the Class H Units, ETE and ETP also agreed to certain adjustments to the prior incentive distribution relinquishments in order to ensure that the incentive distribution relinquishments are fixed amounts for each quarter to which the incentive distribution relinquishments are in effect.

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014.

In connection with ETE's acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG's regasification facility and the development of a liquefaction project at Trunkline LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions totaling $180 million during the years ending December 31, 2016 through 2019.

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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,	
	2013	2012
Audit fees[1]	$5,989,000	$4,448,000
Audit related fees[2]	682,300	25,000
Tax fees[3]	—	1,525
Total	$6,671,300	$4,474,525

(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 2013 for financial statement audits of subsidiary entities in connection with the contribution of SUGS from Southern Union to Regency and the sale of Southern Union's distribution operations. Includes fees in 2013 for audits of Sunoco's benefit plans. Includes fees in 2013 and 2012 in connection with the service organization control report on Southern Union's centralized data center.

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

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 of Directors (Principal Executive Officer)	February 27, 2014
/s/ Martin Salinas, Jr.	Chief Financial Officer	February 27, 2014