Energy Transfer Partners, L.P.
Form 10-K
March 02, 2015
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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, 2014

OR

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

Commission file number 1-11727
ENERGY TRANSFER PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)
Registrant's telephone number, including area code: (214) 981-0700
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.
Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ No ý
The aggregate market value as of June 30, 2014, 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 $16.93 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 18, 2015, the registrant had 357,487,778 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, LLC
CrossCountry	CrossCountry Energy, LLC
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EPA	U.S. Environmental Protection Agency

ET Crude Oil	Energy Transfer Crude Oil Company, 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

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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 Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
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
HOLP	Heritage Operating, L.P.
IDRs	incentive distribution rights
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a subsidiary of ETE
LCL	Lake Charles LNG Export Company, LLC, a subsidiary of ETP and ETE
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas
MACS	Mid-Atlantic Convenience Stores, LLC
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
NYSE	New York Stock 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 Holdings	PEPL Holdings, LLC
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Retail Holdings	ETP Retail Holdings, a joint venture between subsidiaries of ETC OLP and Sunoco, Inc.
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle

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SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas)
SUGS	Southern Union Gas Services
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Susser	Susser Holdings Corporation
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle

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 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 $21.88 billion as of January 30, 2015). 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, CrossCountry and ET Rover Pipeline LLC. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- Liquids operations, including NGL transportation, storage and fractionation services primarily through Lone Star.
- Product and crude oil operations, including the following:
  - product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco, Inc., Susser and Sunoco LP.

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The following chart summarizes our organizational structure as of December 31, 2014. For simplicity, certain immaterial entities and ownership interest have not been depicted.

(1) Pursuant to an agreement between ETE and ETP entered into in December 2014, ETE has agreed to transfer its 45% equity interest in the Bakken Pipeline Project to ETP. This transaction is expected to close in March 2015.

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 2014 and Beyond

Strategic Transactions

Our significant strategic transactions in 2014 and beyond included the following, as discussed in more detail herein:

- In January 2015, ETP announced that its Board of Directors approved an increase in its quarterly distribution to $0.995 per unit ($3.98 annualized) on ETP Common Units for the quarter ended December 31, 2014, representing an increase of $0.30 per Common Unit on an annualized basis, or 8.2%, compared to the fourth quarter of 2013.
- In January 2015, ETP and Regency entered into a definitive merger agreement, as amended on February 18, 2015 (the "Merger Agreement"), pursuant to which Regency will merge with a wholly-owned subsidiary of ETP, with Regency continuing as the surviving entity and becoming a wholly-owned subsidiary of ETP (the "Regency Merger"). At the effective time of the Regency Merger (the "Effective Time"), each Regency common unit and Class F unit will be converted into the right to receive 0.4066 ETP Common Units, plus a number of additional ETP Common Units equal to $0.32 per Regency common unit divided by the lesser of (i) the volume weighted average price of ETP Common Units for the five trading days ending on the third trading day immediately preceding the Effective Time and (ii) the closing price of ETP Common Units on the third trading day immediately preceding the Effective Time, rounded to the nearest ten thousandth of a unit. Each Regency series A preferred unit will be converted into the right to receive a preferred unit representing a limited partner interest in ETP, a new class of units in ETP to be established at the Effective Time. The transaction is subject to other customary closing conditions including approval by Regency's unitholders. The transaction is expected to close in the second quarter of 2015.
- In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline (collectively, the "Bakken pipeline project"), and $879 million in cash (less amounts funded prior to closing by ETE for capital expenditures for the Bakken pipeline project) in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016. This transaction is expected to close in March 2015.
- In October 2014, Sunoco LP acquired MACS from a subsidiary of ETP in a transaction valued at approximately $768 million. The transaction included approximately 110 company-operated retail convenience stores and 200 dealer-operated and consignment sites from MACS.
- In August 2014, ETP and Susser completed the merger of an indirect wholly-owned subsidiary of ETP, with and into Susser, with Susser surviving the merger as a subsidiary of ETP for total consideration valued at approximately $1.8 billion (the "Susser Merger").
- In February 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, 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 2014, we sold 18.9 million of the AmeriGas common units that we originally received in connection with the contribution of our Propane Business to AmeriGas in January 2012.

Significant Organic Growth Projects

Our significant announced organic growth projects in 2014 included the following, as discussed in more detail herein:

- In November 2014, ETP and Regency announced that Lone Star will construct a 533 mile, 24- and 30-inch NGL pipeline from the Permian Basin to Mont Belvieu, Texas and convert Lone Star's existing West Texas 12-inch NGL pipeline into crude oil/condensate service. The new pipeline and conversion projects, estimated to cost between $1.5 billion and $1.8 billion, are expected to be operational by the third quarter of 2016 and the first quarter of 2017, respectively.
- In November 2014, ETP announced its plans to construct two new 200 MMcf/d cryogenic gas processing plants and associated gathering systems in the Eagle Ford and Eaglebine production areas. ETP expects to have the first plant online by June 2015 and the second plant by the fourth quarter of 2015.

- In November 2014, ETP and Regency announced that Lone Star will construct a third natural gas liquids fractionator at its facility in Mont Belvieu, Texas, which will bring Lone Star's total fractionation capacity at Mont Belvieu to 300,000 Bbls/d. Lone Star's third fractionator is scheduled to be operational by December 2015.

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- In October 2014, ETE, ETP and Phillips 66 formed two joint ventures to develop the previously announced Dakota Access Pipeline ("DAPL") and Energy Transfer Crude Oil Pipeline ("ETCOP") projects. ETP and ETE hold an aggregate interest of 75% in each joint venture and ETP operates both pipeline systems. Phillips 66 owns the remaining 25% interests and funds its proportionate share of the construction costs. The DAPL and ETCOP projects are expected to begin commercial operations in the fourth quarter of 2016.
- In June 2014, ETP announced a natural gas pipeline project (now called "Rover") to connect Marcellus and Utica shale supplies to markets in the Midwest, Great Lakes, and Gulf Coast regions of the United States and Canada. ETP has secured multiple, long-term binding shipper agreements on Rover. As a result of these binding agreements, the pipeline is substantially subscribed with 15- and 20-year fee-based contracts to transport up to 3.25 Bcf/d of capacity. Also, ETP recently announced that AE–Midco Rover, LLC ("AE–Midco"), has exercised its option to increase its equity ownership interest in Rover. As a result, AE–Midco (and an affiliate of AE–Midco) will own 35% of Rover and ETP will own 65%.

Segment Overview

See Note 15 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 7,700 miles of natural gas transportation pipelines with approximately 14.1 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.

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 segment, we directly own and operate approximately 12,800 miles of interstate natural gas pipeline with approximately 11.3 Bcf per day 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 Panhandle, 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.

We are currently developing plans to convert a portion of the Trunkline gas pipeline to crude oil transportation.

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The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services.

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 7,200 miles of in service natural gas and NGL gathering pipelines with approximately 5.7 Bcf/d of gathering capacity, 6 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 4.6 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.

Liquids Transportation and Services Segment

Liquids 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 liquids 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, four NGL and propane fractionation facilities with an aggregate capacity of 325,000 Bbls/d and NGL storage facilities with aggregate working storage capacity of approximately 53 million Bbls. Three NGL and propane fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, one NGL 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

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of NGL pipelines including a 50% interest in the joint venture that owns the Liberty pipeline, an approximately 87-mile NGL pipeline and the recently converted 83-mile Rio Bravo crude oil pipeline.

Liquids 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.

Investment in Sunoco Logistics Segment

The Partnership's interests in Sunoco Logistics consist of a 1.9% general partner interest, 100% of the IDRs and 67.1 million Sunoco Logistics common units representing 29.7% of the limited partner interests in Sunoco Logistics as of December 31, 2014. 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 expanded its operations of pipeline transportation, acquisition, storage and marketing of NGLs. In addition, Sunoco Logistics has ownership interests in several product pipeline joint ventures.

Sunoco Logistics' crude oil pipelines transport crude oil in the southwest and midwest United States, principally in Oklahoma and Texas. Sunoco Logistics' crude oil pipelines consist of approximately 5,300 miles of crude oil trunk pipelines for high-volume, long-distance transportation, 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 proprietary fleet of approximately 335 crude oil transport trucks and approximately 135 crude oil truck unloading facilities, as well as third-party assets.

Sunoco Logistics' terminal facilities consist of crude oil, refined products and NGL terminals which receive 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 48 million barrels, including the 25 million barrel Nederland, Texas crude oil and NGL terminal; the 6 million barrel Eagle Point, New Jersey refined products and crude oil terminal; the 3 million barrel Marcus Hook, Pennsylvania refined products and NGL facility (the "Marcus Hook Industrial Complex"); approximately 39 active refined products marketing terminals located in the northeast, midwest and southwest United States; and refinery terminals located in the northeast United States.

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Sunoco Logistics' products pipelines transport refined products and NGLs 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' products pipelines consist of approximately 2,400 miles of refined products and NGL pipelines and joint venture interests in four products pipelines in selected areas of the United States.

Retail Marketing Segment

Our retail marketing business is conducted through various wholly-owned subsidiaries as well as through Sunoco LP, which the Partnership controls through its ownership of the general partner.

Our retail marketing and wholesale fuel distribution operations include the following activities conducted in 30 states, primarily on the east coast, midwest and south regions of the United States:

- Sales of motor fuel (gasoline and diesel) and merchandise at company-operated retail locations and branded convenience stores.
- Distribution of gasoline, diesel and other petroleum products to convenience stores, independent dealers, distributors and other commercial customers.

All Other Segment

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

- We own an investment in Regency common and Class F units, which were received by Southern Union (now Panhandle) in exchange for the contribution of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013.
- Sunoco, Inc. 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, Inc. has a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.
- We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation. For the off-system gas, we purchase gas or act as an agent for small independent producers that may not have marketing operations.
- We 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 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 a 40% interest in LCL, which is developing a LNG liquefaction project, as described further under "Asset Overview – All Other" below.

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

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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 2017.

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 3,800 miles of natural gas pipeline
- Bammel storage facility with 52.5 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 a strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, and our Bammel storage facility.

The Bammel storage facility has a total working gas capacity of approximately 52.5 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, 2014, we had approximately 9.3 Bcf committed under fee-based arrangements with third parties and approximately 40.2 Bcf stored in the facility for our own account.

East Texas Pipeline

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

The East Texas pipeline connects three treating facilities, one of which we own, with our Southeast Texas System. The East Texas pipeline serves 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.

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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 65% 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.

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 ETP Holdco.

Trunkline Gas Company

- 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 ETP Holdco.

We are currently developing plans to convert a portion of the Trunkline gas pipeline to crude oil transportation.

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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 KMI

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.

Midstream

The following details our assets in the midstream segment.

Southeast Texas System

- Approximately 6,400 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 NGL pipelines and then to Lone Star.

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.

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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 1,160 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 to Lone Star.

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 conditioning facility and our recently commissioned Rebel processing plant with capacity of 130 MMcf/d. We also own approximately 50 miles of gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

Liquids Transportation and Services

The following details our assets in the liquids transportation and services segment. Certain assets, as discussed 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 1,170 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.

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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.

Rio Bravo Pipeline

- Aggregate capacity of 100,000 Bbls/d
- Approximately 83 miles of crude oil transmission pipeline

In 2014, we converted approximately 80 miles of natural gas pipeline from our HPL and Southeast Texas Systems to crude service and constructed approximately 3 miles of new crude oil pipeline.

Mont Belvieu Facilities

- Working storage capacity of approximately 48 million Bbls
- Approximately 185 miles of NGL transmission pipelines
- 300,000 Bbls/d NGL and propane fractionation facilities

The Mont Belvieu storage facility, owned by Lone Star, is an integrated liquids storage facility with over 48 million Bbls of salt dome 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 October 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 4.5 million Bbls

The Hattiesburg storage facility, owned by Lone Star, is an integrated liquids storage facility with approximately 4.5 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.

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.

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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 5,300 miles of crude oil trunk pipelines for high-volume, long-distance transportation, 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 3,150 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 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. In December 2014, Sunoco Logistics acquired an additional 28.3% ownership interest in the West Texas Gulf Pipe Line Company from Chevron Pipe Line Company, increasing its controlling financial interest in the consolidated subsidiary to 88.6%. The remaining 11.4% was acquired from Southwest Pipeline Holding Company, LLC in January 2015.

The Southwest United States pipeline system also includes the Oklahoma crude oil pipeline and gathering system that consists of approximately 1,050 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 originate in Longview, Texas and pass through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky and Ohio, and terminate 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 Sunoco Logistics' assets, which include approximately 335 crude oil transport trucks and approximately 135 crude oil truck unloading facilities, as well as third-party truck, rail and marine assets. 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;
- 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.

Terminal Facilities

Sunoco Logistics' 39 active 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. 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.

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

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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, 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 and NGLs. The terminal receives, stores, and distributes crude oil, NGLs, 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 25 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 Sunoco Logistics' crude oil pipelines, the terminal can also receive crude oil through a number of other pipelines, including the DOE. 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 DOE. The Nederland Terminal can also receive NGLs in connection with the Mariner South pipeline.

- 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 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.

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, which is operated by PES. 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 Industrial Complex: In 2013, Sunoco Logistics acquired Sunoco, Inc.'s Marcus Hook Industrial Complex. The acquisition included terminalling and storage assets with a capacity of approximately 3 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 Industrial Complex also provides customers with the use of industrial space and equipment at the facility, as well as logistical, utility and infrastructure services.

- 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 marine vessels (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 6 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 NGLs from local producers and a refinery in western Ohio. The terminal can receive and ship by pipeline in both directions and has a truck loading and offloading rack.

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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.

Products Pipelines

Sunoco Logistics owns and operates approximately 2,400 miles of products pipelines in several regions of the United States. The products pipelines primarily transport refined products and NGLs 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 products pipeline owned by our consolidated joint venture, Inland Corporation ("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 products pipelines are regulated by the FERC and the Pennsylvania Public Utility Commission ("PA PUC"), among other state regulatory agencies.

- Mariner East: Mariner East 1 and Mariner East 2 are pipeline projects to deliver NGLs from the Marcellus and Utica Shale areas in western Pennsylvania, West Virginia and eastern Ohio to the Marcus Hook Industrial Complex on the Delaware River in Pennsylvania, where it will be processed, stored and distributed to various local, domestic and waterborne markets. Mariner East 2 is the second phase of the project, which will expand the total take-away capacity to 345,000 Bbls/d. Mariner East 1 commenced initial operations in the fourth quarter of 2014 and Mariner East 2 is expected to commence operations in the fourth quarter 2016.
- Mariner South: The Mariner South pipeline provides transportation of propane and butane products from the Mont Belvieu, Texas area to the Nederland Terminal, where such products can be sold by way of ship. Mariner South commenced initial operations in December 2014, with an initial capacity of 200,000 Bbls/d of NGLs and other products.
- Inland: Inland is Sunoco Logistics' 83.8% owned joint venture consisting of approximately 350 miles of active 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 products pipelines, summarized in the following table:

Pipeline	Equity Ownership		Pipeline Mileage
Explorer Pipeline Company[1]	13.3	%	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. An additional 3.9% ownership interest was purchased in the first quarter of 2014.

(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 and wholesale distribution segment consists of the retail sale of motor fuel and merchandise through company-operated locations, and the distribution of branded and unbranded motor fuel purchased primarily from refiners to company-operated retail sites, independently operated retail sites, as well as other wholesale and commercial customers.

The business is operated through various wholly-owned subsidiaries as well as through Sunoco LP which the Partnership controls through its ownership of the general partner. The Partnership currently plans to contribute all of the retail operations and fuel distributions business of our wholly-owned subsidiaries to Sunoco LP in future periods. In October 2014, we completed the first of such transactions, when one of the Partnership's subsidiaries contributed all of the ownership of MACS to Sunoco LP.

The retail marketing segment has a portfolio of outlets operating under three channels of trade: company-operated, dealer-operated and distributor-operated sites. The portfolio of sites in these channels differ in various ways including: site ownership and operation, product distribution to the outlets, and types/brands of products and services provided. Company-operated sites, which are operated by one of our subsidiaries, and independent dealer-operated sites are sites at which fuel products are delivered directly to the site by company-operated trucks or by contract carriers. One of our subsidiaries may own or lease the property and collect rental income or an independent dealer owns or leases the property. Independent dealers are supplied under a contract with one of our subsidiaries. Most of the company-operated sites include a convenience store under the Aplus®, Stripes®, MACS, Tigermarket or Aloha Island Mart® brands. As of December 31, 2014, our subsidiaries were operating or supplying under a long-term contract a total of 75 Sunoco®-branded outlets on turnpikes and expressways in Pennsylvania, New Jersey, New York, Maryland, Ohio and Delaware.

Distributor outlets are primarily Sunoco®-branded sites in which the distributor takes delivery of fuel products at a terminal where branded products are available. Our subsidiaries supply the distributor under a long-term contract, but do not own, lease or operate these distributor locations.

The highest concentration of retail outlets are located in Texas, Pennsylvania, New York, Florida and Ohio.

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The following table sets forth our retail gasoline outlets at December 31, 2014 (including sites operated through our wholly-owned subsidiaries and Sunoco LP):

Retail and Fuel Distribution Outlets:	Sunoco LP	Wholly-Owned Subsidiaries	Total
Company-Owned or Leased:			
Company-Operated[1]	155	1,096	1,251
Dealer-Operated	138	425	563
Total	293	1,521	1,814
Dealer Owned	655	541	1,196
Distributor Outlets	—	3,640	3,640
Total	948	5,702	6,650

[1] Gasoline and diesel throughput per company-operated site averaged 177,236 gallons per month during 2014.

Brands

We manage a portfolio of strong proprietary fuel and convenience store brands through our retail and wholesale portfolio of outlets, including Sunoco®, Stripes®, Aplus®, and Aloha Island Mart®.

Of the total retail outlets that are company-operated or operating under a long-term contract by an independent third-party, 4,961 operate under the Sunoco® fuel brand as of December 31, 2014. The Sunoco® brand is positioned as a premium fuel brand. Brand improvements in recent years have focused on physical image, customer service and product offerings. In addition, Sunoco, Inc. believes its brands and high performance gasoline business have benefited from its sponsorship agreements with NASCAR®, INDYCAR® and the NHRA®. Under the sponsorship agreement with NASCAR®, which continues until 2022, Sunoco® is the Official Fuel of NASCAR® and APlus® is the Official Convenience Store of NASCAR®. Sunoco, Inc. has exclusive rights to use certain NASCAR® trademarks to advertise and promote Sunoco, Inc. products and is the exclusive fuel supplier for the three major NASCAR® racing series. The sponsorship agreements with INDYCAR® and NHRA® continue through 2018 and 2024, respectively.

In addition to operating premium proprietary brands, our subsidiaries operate as a significant distributor to multiple top-tier fuel brands, including Exxon®, Mobil®, Valero®, Shell® and Chevron®.

Convenience Store and Restaurant Operations

Our subsidiaries operate 1,185 convenience stores primarily under our proprietary Stripes®, Aplus® and Aloha Island Mart® convenience store brands as of December 31, 2014. These stores complement sales of fuel products with a broad mix of merchandise, food service, and other services. As of December 31, 2014, 474 of these stores featured in-store restaurants allowing us to make fresh food on the premises daily. Laredo Taco Company® is our in-house proprietary restaurant operation featuring breakfast and lunch tacos, a wide variety of handmade authentic Mexican food and other hot food offerings targeted to local populations in the markets served. Some of these stores also offer other proprietary and third party food options, including Subway® sandwiches and Godfather® pizza.

The following table sets forth information concerning the company-operated convenience stores during 2014:

Number of stores at December 31, 2014	1,185	
Merchandise sales (thousands of dollars/store/month)	$127	
Merchandise margin (% sales)	31.4	%

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

All Other

Liquefaction Project

LCL, an entity owned 60% by ETE and 40% by ETP, is in the process of developing the liquefaction project in conjunction with BG pursuant to a project development agreement entered into in September 2013. Pursuant to this agreement, each of LCL and

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BG are obligated to pay 50% of the development expenses for the liquefaction project, subject to reimbursement by the other party if such party withdraws from the project prior to both parties making an affirmative FID to become irrevocably obligated to fully develop the project, subject to certain exceptions. The liquefaction project is expected to consist of three LNG trains with a combined design nameplate outlet capacity of 16.2 metric tonnes per annum. Once completed, the liquefaction project will enable LCL to liquefy domestically produced natural gas and export it as LNG. By adding the new liquefaction facility and integrating with the existing LNG regasification/import facility, the enhanced facility will become a bi-directional facility capable of exporting and importing LNG. BG is the sole customer for the existing regasification facility and is obligated to pay reservation fees for 100% of the regasification capacity regardless of whether it actually utilizes such capacity pursuant to a regasification services agreement that terminates in 2030. The liquefaction project will be constructed on 400 acres of land, of which 200 acres are owned or leased by Lake Charles LNG and 200 acres are to be leased by LCL under a long-term lease from the Lake Charles Harbor and Terminal District or purchased by LCL pursuant to the exercise of an option agreement entered into in connection with the liquefaction project.

The construction of the liquefaction project is subject to each of LCL and BG making an affirmative FID to proceed with the project, which decision is in the sole discretion of each party. In the event an affirmative FID is made by both parties, LCL and BG will enter into several agreements related to the project, including a liquefaction services agreement pursuant to which BG will pay LCL for liquefaction services on a tolling basis for a minimum 25-year term with evergreen extension options for 20 years. In addition, a subsidiary of BG, a highly experienced owner and operator of LNG facilities, would oversee construction of the liquefaction facility and, upon completion of construction, manage the operations of the liquefaction facility on behalf of LCL. Subject to receipt of regulatory approvals, we anticipate that each of LCL and BG will make an affirmative FID in 2016 and then commence construction of the liquefaction project in order to place the first LNG train in service in late 2019 and the second and third trains in service during 2020.

The export of LNG produced by the liquefaction project from the U.S. will be undertaken under long-term export authorizations issued by the DOE to Lake Charles Exports, LLC (“LCE”), which is currently a jointly owned subsidiary of BG and ETP and following FID, will be 100% owned by BG. In July 2011, LCE obtained a DOE authorization to export LNG to countries with which the U.S. has or will have Free Trade Agreements (“FTA”) for trade in natural gas (the “FTA Authorization”). In August 2013, LCE obtained a conditional DOE authorization to export LNG to countries that do not have an FTA for trade in natural gas (the “Non-FTA Authorization”). The FTA Authorization and Non-FTA Authorization have 25- and 20-year terms, respectively. In January 2013, LCL filed for a secondary, non-cumulative FTA and Non-FTA Authorization to be held by LCL. FTA Authorization was granted in March 2013 and we expect the DOE to issue the Non-FTA Authorization to LCL in due course.

Prior to being authorized to export LNG, we must also receive (i) approvals from the FERC to construct and operate the facilities, (ii) wetlands permits from the U.S. Army Corps of Engineers (“USACE”) to perform wetlands mitigation work and to perform modification and dredging work for the temporary and permanent dock facilities at the Lake Charles LNG facilities, and (iii) air permits from the Louisiana Department of Environmental Quality (“LDEQ”) for emissions from the liquefaction project. We expect to receive the wetlands permit from the USACE and the air permit from the LDEQ in the third quarter of 2015.

In January 2015, LCL received from FERC its notice of schedule. The FERC notice of schedule provides an important timeline for the issuance of the Notice of Availability of Final Environmental Impact Statement (the “FEIS”). The issuance of the FEIS is scheduled for August 14, 2015, which then starts the 90-day period in which other federal agencies are to complete their review of the project and issue any required agency authorizations. The federal decision deadline date is November 12, 2015 and the FERC authorization for the project is anticipated during this 90-day period.

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:

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.

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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.

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.

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 Products

In markets served by our products and crude oil pipelines, we face competition from other pipelines. Generally, pipelines are the lowest cost method for long-haul, overland movement of products and crude oil. 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 products 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 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

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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 and Sunoco LP.

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, gas and electric utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that 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 exploration and production activities. The discovery and development of new shale formations across the United States has created an abundance of natural gas and crude oil resulting in a negative impact on prices in recent years for natural gas and in recent months for crude oil. 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, 2014, 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.

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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. On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to the 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in August 2015.

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective May 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015.

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.

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: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) 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 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.

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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 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

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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 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 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 Products Pipelines. Some of our crude oil and 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 certain gas 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. 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. Most recently, in an August 2014 U.S. Government Accountability Office (the “GAO”) report to Congress, the GAO acknowledged PHMSA’s continued assessment of the safety risks posed by these gathering lines as part of the rulemaking process, and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. While we believe our pipeline operations are in substantial compliance with applicable pipeline safety laws, safety laws and regulations may be

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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, the NGPSA and HLPSA 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 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, capital expenditures 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, operating and maintenance 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 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, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("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

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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, as amended, ("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 certain wastes associated with the exploration, development and production of crude oil and natural gas. 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 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, 2014 and 2013, accruals of $391 million and $395 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, for example, certain matters assumed in connection with our acquisition of the HPL System, our acquisition of Transwestern, potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors, and the predecessor owner's share of certain environmental liabilities of ETC OLP.

The Partnership is subject to extensive and frequently changing federal, state and local laws and regulations, including 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 remediation efforts at many of Sunoco, Inc.'s facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $363 million and $377 million at December 31, 2014 and 2013, respectively, 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, Inc., 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, 2014 the captive

insurance company held $267 million of cash and investments.

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.

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

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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 non-hazardous 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 or issue is evaluated individually based upon information available for the site or 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 allows 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, 2014, 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.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants,

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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 regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which rulemaking proposed to revise the National Ambient Air Quality Standard ("NAAQS") for ozone between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended, 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 state waters and 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 other products. The Clean Water Act, or amended by the federal Oil Pollution Act of 1990, as amended, ("OPA"), 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 OPA 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 PHMSA, 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.

Climate Change. Based on findings made by the EPA that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD") and Title V permitting reviews for greenhouse gas emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant 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 typically developed by the states. Any regulatory or permitting obligation that limits emissions of greenhouse gases could

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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 adopted regulations requiring the annual reporting of greenhouse gas emissions from certain petroleum and natural gas sources in the United States, including onshore oil and natural gas production, processing, transmission, storage and distribution facilities. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual greenhouse gas emissions reporting is currently required to include greenhouse gas emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring greenhouse gas emissions from certain of our facilities in accordance with current greenhouse emissions reporting requirements in a manner that we believe is in substantial compliance with applicable reporting obligations and are currently assessing the potential impact that the December 9, 2014 proposed rule may have on our future reporting obligations, should the proposal be adopted.

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. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45% from 2012 levels by 2025.

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 30, 2015, we employed 25,682 persons, 1,609 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 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 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 and Sunoco LP may issue additional common units, which may increase the risk that Sunoco Logistics or Sunoco LP will not have sufficient available cash to maintain or increase their per unit distribution level.

Sunoco Logistics' and Sunoco LP's partnership agreements allow the issuance of an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by Sunoco Logistics or Sunoco LP will have the following effects:

- Unitholders' current proportionate ownership interest in Sunoco Logistics or Sunoco LP, 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' or Sunoco LP's common units may decline.

The payment of distributions on any additional units issued by Sunoco Logistics and Sunoco LP may increase the risk that Sunoco Logistics and Sunoco LP may not have sufficient cash available to maintain or increase their 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, 2014, ETE owned 30.8 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 April 2014, 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, 2014, we had approximately $19.34 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 $2.04 billion of our consolidated debt as of December 31, 2014 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.

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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, 2014, ETE and its affiliates held approximately 8.7% of our outstanding Common Units and our officers and directors held less than 1% of our outstanding Common Units.

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. If the Regency Merger is completed and the Bakken Pipeline Transaction is completed, ETE's aggregate ownership percentage of the outstanding ETP Common Units would decrease to approximately 5% on a pro forma basis.

Our General Partner may, in its sole discretion, approve the issuance of partnership securities and specify the terms of such partnership securities.

Pursuant to our partnership agreement, our General Partner has the ability, in its sole discretion and without the approval of the Unitholders, to approve the issuance of securities by the Partnership at any time and to specify the terms and conditions of such securities. The securities authorized to be issued may be issued in one or more classes or series, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership securities), as shall be determined by our General Partner, including:

- the right to share in the Partnership's profits and losses;
- the right to share in the Partnership's distributions;
- the rights upon dissolution and liquidation of the Partnership;
- whether, and the terms upon which, the Partnership may redeem the securities;
- whether the securities will be issued, evidenced by certificates and assigned or transferred; and
- the right, if any, of the security to vote on matters relating to the Partnership, including matters relating to the relative rights, preferences and privileges of such security.

Please see "We may sell additional limited partner interests, diluting existing interests of Unitholders." above.

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

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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 $0.2638 per common unit per quarter would reduce Sunoco Partners' percentage of the incremental cash distributions above $0.0958 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.

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.

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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.

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,” which standard 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 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;
- provides that 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;

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- provides that our General Partner may 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, including the Unitholders, and will not constitute a breach of the partnership agreement;
- provides that our General Partner may, but is not required, in connection with its resolution of a conflict of interest, to seek "special approval" of such resolution by appointing a conflicts committee of the General Partner's board of directors composed of two or more independent directors to consider such conflicts of interest and to recommend action to the board of directors, and any resolution of the conflict of interest by the conflicts committee shall be conclusively deemed "fair and reasonable" to us;
- 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.

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- 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.

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.

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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 and NGLs. 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.

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.

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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 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 products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined in these areas. In either case, the volumes of crude oil or 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.

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

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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, Inc.'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.

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.

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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 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 41.8% of the company- or dealer-operated retail service stations where we currently control

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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, 2014, our consolidated balance sheet reflected $6.42 billion of goodwill and $2.09 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 Lake Charles 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.

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;

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- 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 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.

Certain producers who are connected to our systems represent a material source of our supply of natural gas. 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.

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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.

During 2014, Kinder Morgan, Inc., EDF Inc., Natural Gas Exchange Inc., Calpine Energy Services, L.P., and XTO Energy Inc. collectively accounted for approximately 32.9% 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.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP has 10- and 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 2014 revenue.

During 2014, BG Energy Holdings, Chesapeake Energy Marketing, Inc., Ameren Corporation, EnCana Marketing (USA), Inc., and Exelon Generation Company, LLC collectively accounted for 50.4% 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.

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.

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

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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.

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

Transportation provided on our common carrier interstate crude oil and 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

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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.

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

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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. Most recently, in an August 2014 GAO report to Congress, the agency acknowledged PHMSA's continued assessment of the safety risks posed by these gathering lines as part of rulemaking process, and recommended that PHMSA move forward with rulemaking to address such lines.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing, and verification of the maximum allowable pressure of certain pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and from $1.0 million to $2.0 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

Our business involves the generation, handling and disposal of hazardous substances, hydrocarbons and wastes and may be adversely affected by environmental and worker health and safety laws and regulations.

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, impose specific health and safety standards addressing worker protection, and impose substantial liabilities for pollution resulting from our operations. Several governmental authorities, such as the EPA and state agencies 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 December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which rulemaking proposed to revise the NAAQS for ozone between 65 to 70 ppb for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If EPA lowers the ozone standard, states could be required to implement more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. We have previously been able to satisfy the more stringent NOx

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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 any new, more stringent 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, Inc. 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, Inc. These allegations or other product liability claims against Sunoco, Inc. 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.

The EPA has determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules under the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for greenhouse gas emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions, 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 annual reporting of greenhouse gas emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States, which includes certain of our operations. More recently, on December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual greenhouse gas emissions reporting is currently required to include greenhouse gas emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. 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. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45 percent from 2012 levels by 2025.

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.

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Reporting and recordkeeping requirements also could significantly increase operating costs and expose us to penalties for non-compliance, and 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.

In October 2011, 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. However, in September 2012, the CFTC's position limits rules were vacated by the U.S. District Court for the District of Columbia. In November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. The associated rules require us, in connection with covered derivative activities, to comply with such requirements or take steps to qualify for an exemption to such requirements. We must obtain approval from the board of directors of our General Partner and make certain filings in order to rely on the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks. The application of mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing and exchange trading.

In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. The application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact our liquidity and reduce cash available to us for capital expenditures, reducing our ability to execute hedges to reduce risk and protect cash flow.

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, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, or reduce our ability to monetize or restructure existing derivative contracts. 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.

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.

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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.

Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and other related restrictions arising after the Deepwater Horizon incident in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In response to the Deepwater Horizon incident and resulting oil spill in the United States Gulf of Mexico in 2010, the federal Bureau of Ocean Energy Management and the federal Bureau of Safety and Environmental Enforcement, each agencies of the U.S. Department of the Interior, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. These governmental agencies have implemented and enforced new rules, Notices to Lessees and Operators and temporary drilling moratoria that imposed safety and operational performance measures on exploration, development and production operators in the Gulf of Mexico or otherwise resulted in a temporary cessation of drilling activities. Compliance with these added and more stringent regulatory restrictions in addition to any uncertainties or inconsistencies in current decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development and oil spill-response plans could adversely affect or delay new drilling and ongoing development efforts. Moreover, these governmental agencies are continuing to evaluate aspects of safety and operational performance in the Gulf of Mexico and, as a result, developing and implementing new, more restrictive requirements. One example is the 2013 amendments to the federal Workplace Safety Rule regarding the utilization of a more comprehensive SEMS, which amended rule is sometimes referred to as SEMS II. A second, and more recent, example is the August 2014 Advanced Notice of Proposed Rulemaking that ultimately seeks to bolster the offshore financial assurance and bonding program. Among other adverse impacts, these additional measures could delay or disrupt our and our customers' operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding requirements and incurrence of associated added costs, limit operational activities in certain areas, or cause us or out customers to incur penalties, fines, or shut-in production. If similar material spill incidents were to occur in the future, 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 natural gas exploration, development and production. We cannot predict with any certainty the full impact of any new laws or regulations on our customers' drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. The occurrence of any of these developments has the potential to adversely impact our business as well as our financial position, results

of operation 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

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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 service licenses and which would ultimately affect our ability to recover the costs incurred to acquire and integrate our butane blending assets.

Our business could be affected adversely by union disputes and strikes or work stoppages by unionized employees. As of December 31, 2014, approximately 6% of our workforce is covered by a number of collective bargaining agreements with various terms and dates of expiration. 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, Inc.’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, Inc. 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, Inc.'s competitive position. Additionally, if the implementation of our outsourcing initiatives is disruptive to our

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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, Inc. brand, increase our compliance costs, or otherwise harm our business.

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.

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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.

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.

LCL is dependent on project financing to fund the costs necessary to construct the liquefaction project. If project financing is unavailable to supply the funding necessary to complete the liquefaction project, LCL may not be able to secure alternative funding and FID may not be achieved.

LCL, an entity owned 60% by ETE and 40% by ETP, is in the process of developing a proposed liquefaction project in conjunction with BG Group plc ("BG") pursuant to a project development agreement entered into in September 2013. Pursuant to this agreement, each of LCL and BG are obligated to pay 50% of the development expenses for the liquefaction project, subject to reimbursement by the other party if such party withdraws from the project prior to both parties making a final investment decision ("FID") to become irrevocably obligated to fully develop the project, subject to certain exceptions. Through December 31, 2014, LCL had incurred $75 million of development costs associated with the liquefaction project that were funded by ETE and ETP, and ETE and ETP have indicated that they intend to provide the funding necessary for the remaining development costs, but they have no obligation to do so. If ETE and ETP are unwilling or unable to provide funding to LCL for its share of the remaining development costs, or if BG is unwilling or unable to provide funding for its share of the remaining development costs, the liquefaction project could be delayed or cancelled.

The liquefaction project is subject to the right of each of LCL and BG to withdraw from the project in its sole discretion at any time prior to an affirmative FID.

The project development agreement provides that either LCL or BG may withdraw from the liquefaction project at any time prior to each party making an affirmative FID. LCL's determination of whether to reach an affirmative FID is expected to be based upon a number of factors, including the expected cost to construct the liquefaction facility, the expected revenue to be generated by LCL pursuant to the terms of the liquefaction services agreement anticipated to be entered into between LCL and BG in connection with both parties reaching an affirmative FID, and the terms and conditions of the financing for the construction of the liquefaction facility. BG's determination of whether to reach an affirmative FID is expected be based on a number of factors, including the expected tolling charges it would be required to pay under the terms of the liquefaction services agreement, the costs anticipated to be incurred by BG to purchase natural gas for delivery to the liquefaction facility, the costs to transport natural gas to the liquefaction facility, the costs to operate the liquefaction facility and the costs to transport LNG from the liquefaction facility to customers in foreign markets (particularly Europe and Asia) over the expected 25-year term of the liquefaction services agreement. As the tolling charges payable to LCL under the liquefaction services agreement are anticipated to

be based on a rate of return formula tied to the construction costs and financing costs for the liquefaction facility, these costs are anticipated to also have a significant bearing with respect to BG's determination whether to reach an affirmative FID. As these costs fluctuate based on a variety of factors, including supply and demand factors affecting the price of natural gas in the United States, supply and demand factors affecting the price of LNG in foreign markets, supply and demand factors affecting the costs for construction services for large infrastructure projects in the United States, and general economic conditions, there can be no assurance that both LCL and BG will reach an affirmative FID to construct the liquefaction facility.

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The construction of the liquefaction project remains subject to further approvals and some approvals may be subject to further conditions, review and/or revocation.

The liquefaction project remains subject to (i) the receipt of approval by the FERC to construct and operate the facilities, (ii) approvals and permits from the U.S. Army Corps of Engineers ("USACE") for wetlands mitigation and permanent and temporary marine dock modifications and dredging at the Lake Charles LNG facility and (iii) other governmental and regulatory approvals and permits, including air permits under the Clean Air Act. Furthermore, while a subsidiary of BG has received authorization from the DOE to export LNG to non-FTA countries, the non-FTA authorization is subject to review, and the DOE may impose additional approval and permit requirements in the future or revoke the non-FTA authorization should the DOE conclude that such export authorization is inconsistent with the public interest. Certain of the permits and approvals must be obtained before construction on the liquefaction project can begin and are still under review by state and federal authorities. We do not know whether or when any such approvals or permits can be obtained, or whether any existing or potential interventions or other actions by third parties will interfere with its ability to obtain and maintain such permits or approvals. The failure by LCL to timely receive and maintain the remaining approvals necessary to complete and operate the liquefaction project could have a material adverse effect on its operations and financial condition.

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, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax

laws that affect publicly traded partnerships. If successful, the Obama administration's proposal or other similar proposals could eliminate 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 U.S. federal income tax purposes. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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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, Inc. and the ETP 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 in determining unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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.

Risks Related to ETP's Pending Acquisition of Regency

The completion of the Regency Merger is subject to the satisfaction of certain conditions to closing, and the date that the Regency Merger would be consummated is uncertain.

The completion of the Regency Merger is subject to the absence of a material adverse change to the business or results of operation of ETP and Regency, the receipt of necessary regulatory approvals, the approval of the Regency Merger

by a majority of the outstanding Regency common units and the satisfaction or waiver of other conditions specified in the merger agreement related to the Regency transaction. In the event those conditions to closing are not satisfied or waived, we would not complete the Regency Merger.

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While ETP expects to complete the Regency Merger in the second quarter of 2015, the completion date of the Regency Merger might be later than expected due to delays in obtaining required regulatory approvals or other unforeseen events.

Failure to complete the merger, or significant delays in completing the merger, could negatively affect the trading price of ETP's common units and ETP's future business and financial results.

Completion of the merger is not assured and is subject to risks, including the risks that approval of the merger by Regency's unitholders or governmental agencies is not obtained or that other closing conditions are not satisfied. If the merger is not completed, or if there are significant delays in completing the merger, it could negatively affect the trading price of ETP's common units and ETP's future business and financial results, and ETP will be subject to several risks, including the following:

- liability for damages under the terms and conditions of the merger agreement;
- negative reactions from the financial markets, including declines in the price of ETP's common units due to the fact that current prices may reflect a market assumption that the merger will be completed; and
- the attention of ETP's management will have been diverted to the merger rather than its own operations and pursuit of other opportunities that could have been beneficial to ETP.

ETP may have difficulty attracting, motivating and retaining executives and other employees in light of the merger.

Uncertainty about the effect of the merger on ETP's employees may have an adverse effect on ETP and the combined organization. This uncertainty may impair ETP's ability to attract, retain and motivate personnel until the merger is completed. Employee retention may be particularly challenging during the pendency of the merger, as employees may feel uncertain about their future roles with the combined organization. In addition, ETP may have to provide additional compensation in order to retain employees. If ETP's employees depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined organization, the ability of ETP to realize the anticipated benefits of the merger could be reduced. Also, if ETP fails to complete the merger, it may be difficult and expensive to recruit and hire replacements for such employees.

Regency is subject to contractual restrictions while the merger is pending, which could materially and adversely affect each party's business and operations, and, pending the completion of the transaction, our business and operations could be materially and adversely affected.

Under the terms of the Regency Merger agreement, Regency is subject to certain restrictions on the conduct of business prior to completing the transaction, which may adversely affect their ability to execute certain business strategies without first obtaining consent from ETP, including their ability in certain cases to enter into contracts, incur capital expenditures or grow its business. The merger agreement also restricts Regency's ability to solicit, initiate or encourage alternative acquisition proposals with any third party and may deter a potential acquirer from proposing an alternative transaction or may limit our ability to pursue any such proposal. Such limitations could negatively affect our business and operations prior to the completion of the proposed transaction. Furthermore, the process of planning to integrate two businesses and organizations for the post-merger period can divert management attention and resources and could ultimately have an adverse effect on us.

In connection with the pending merger, it is possible that some customers, suppliers and other persons with whom Regency has business relationships may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship as a result of the transaction, which could negatively affect our revenues, earnings and cash flows, as well as the market price of our common units, regardless of whether the transaction is completed.

Lawsuits have been filed against us, Regency, Regency GP LP, Regency GP LP's board of directors, and ETE challenging the merger, and any injunctive relief or adverse judgment for monetary damages could prevent the merger from occurring or could have a material adverse effect on us following the merger.

The Partnership, Regency, Regency GP LP, the directors of the Regency GP LP, and ETE are named defendants in purported class actions and derivative petitions brought by purported Regency unitholders in Dallas County, Texas, generally alleging claims of breach of duties under the partnership agreement, breach of the implied covenant of good faith and fair dealing in connection with the merger transactions, and aiding and abetting arising out of the defendants' pursuit of the merger by way of an allegedly conflicted and unfair process. Similar lawsuits have been filed in the

United States District Court for the Northern District of Texas. The plaintiffs in these lawsuits seek to enjoin the defendants from proceeding with or consummating the merger and, to the extent that the merger is implemented before relief is granted, plaintiffs seek to have the merger rescinded. Plaintiffs also seek money damages and attorneys' fees. One of the conditions to the completion of the merger is that no order, decree, or injunction of any court or agency of competent jurisdiction shall be in effect, and no law shall have been enacted or adopted, that enjoins, prohibits, or makes illegal consummation of any of the transactions contemplated by the merger agreement. A preliminary injunction could delay or jeopardize the completion of the merger, and an adverse judgment granting permanent injunctive relief could indefinitely enjoin

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completion of the merger. An adverse judgment for rescission or for monetary damages could have a material adverse effect on us following the merger.

We will incur substantial transaction-related costs in connection with the merger.

We expect to incur a number of non-recurring merger-related costs associated with completing the merger, combining the operations of the two companies, and achieving desired synergies. These fees and costs will be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal, financial and accounting advisors, filing fees and printing costs. Additional unanticipated costs may be incurred in the integration of Regency and ETP's businesses. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction-related costs over time. Thus, any net benefit may not be achieved in the near term, the long term or at all.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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, Corpus Christi 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, Inc., 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 also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2014, Sunoco, Inc. is a defendant in five cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, 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. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, Vermont, and Pennsylvania cases assert natural resource damage claims. Fact discovery has concluded with respect to an initial set of 19 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, Inc. in these matters. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. 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

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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 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 repair 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 on 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 2015. The timing or outcome of this matter cannot be reasonably determined at this time; however, Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

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, Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

In November 2013, the DOT 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 February 2012 products release by FGT in Baton Rouge, Louisiana. We received an initial assessment of $0.2 million associated with this release. The Partnership is in discussions with the DOT on this matter and hopes to resolve this issue in 2015. The timing or outcome of this matter cannot be reasonably determined at this time. However, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

On or around December 24, 2014, PHMSA issued to ETP's Panhandle a Notice of Proposed Safety Order (the "Notice") regarding the ETP\Panhandle pipeline system. The Notice stated that PHMSA had initiated an investigation of the safety of the ETP/Panhandle pipeline system and specifically referenced two incidents: 1) a November 28, 2013, incident on ETP/Panhandle's 400 line approximately 4.7 miles downstream of the Houstonia compressor station near Hughesville, Missouri, and 2) an October 13, 2014, failure on the ETP/Panhandle 100 line near Centerview, Missouri. The Notice further mentioned other incidents on the ETP/Panhandle pipeline system that PHMSA claims to have addressed with ETP/Panhandle. The Notice also stated that "[a]s a result of [PHMSA's] investigation, it appears that conditions exist on the ETP/Panhandle pipeline system that pose a pipeline integrity risk to public safety, property or the environment." ETP/Panhandle is fully cooperating with PHMSA and its investigation.

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 above 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.

One of the directors of our general partner, James R. (Rick) Perry, the former Governor of Texas, has been named the subject of a pending criminal proceeding arising from a political dispute between the Governor and the political leadership of the Public Integrity Unit of the Travis County (Texas) District Attorney's Office. On August 15, 2014, the Travis County District Attorney's Office caused a county grand jury to return an indictment against Governor Perry for "abuse of official capacity" and "coercion of public servant" in retaliation for constitutional protected statements

Governor Perry made in his capacity as Governor of the State of Texas that he would veto funding for the Travis County Public Integrity Unit if District Attorney Rosemary Lehmberg did not resign after pleading guilty to a charge of driving while intoxicated. Governor Perry has pled “not guilty” to those charges and fully expects the charges against him to be dismissed before the trial on constitutional and factual grounds.

For a description of legal proceedings, see Note 11 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 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 2014			
Fourth Quarter	$69.66	$53.12	$0.9950
Third Quarter	64.13	54.64	0.9750
Second Quarter	58.20	53.62	0.9550
First Quarter	57.00	52.49	0.9350
Fiscal Year 2013			
Fourth Quarter	$57.31	$50.60	$0.9200
Third Quarter	54.85	49.40	0.9050
Second Quarter	53.00	45.16	0.8938
First Quarter	50.71	43.67	0.8938

(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

Common Units

As of February 18, 2015, there were approximately 512,519 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."

Class E Units

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.

Class G Units

In conjunction with the Sunoco Merger, we amended our partnership agreement to create 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, Inc. 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 ETP 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

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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.

Class H Units and Class I Units

Currently Outstanding

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 and (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.

Pending Transaction

In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, ETP will also issue 100 Class I Units, as described below. In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016.

In connection with the transaction, ETP will also issue 100 Class I Units. The Class I Units will be generally entitled to: (i) pro rata allocations of gross income or gain until the aggregate amount of such items allocated to the holders of the Class I Units for the current taxable period and all previous taxable periods is equal to the cumulative amount of all distributions made to the holders of the Class I Units and (ii) after making cash distributions to Class H Units, any additional available cash deemed to be either operating surplus or capital surplus with respect to any quarter will be distributed to the Class I Units in an amount equal to the excess of the distribution amount set forth in our Partnership Agreement, as amended, (the "Partnership Agreement") for such quarter over the cumulative amount of available cash previously distributed commencing with the quarter ending March 31, 2015 until the quarter ending December 31, 2016. The impact of (i) the IDR subsidy adjustments and (ii) the Class I Unit distributions, along with the currently effective IDR subsidies, is included in the table below under "IDR Subsidies and Other Distribution Adjustments" in the column titled "Pro Forma for Class H and Class I Units."

General Partner Interest

As of December 31, 2014, 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.

Incentive Distribution Rights

IDRs represent the contractual right, pursuant to the terms of our partnership agreement, of our general partner 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

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- 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.

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, pending completion of the Bakken Pipeline Transaction between ETE and ETP announced in December 2014. We are required to make distributions of any remaining Available Cash from operating surplus for any quarter in the following manner:

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- 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."

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 8 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

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IDR Subsidies and Other Distribution Adjustments

As described above, our partnership agreement requires certain incentive distributions to the holders of the IDRs. In connection with transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods based on (i) the currently effective partnership agreement provisions, (ii) the assumed closing of the issuance of additional Class H Units and Class I Units, which is expected to occur in March 2015, and (iii) the assumed closing of the Regency Merger, which is expected to occur in the second quarter of 2015:

Years Ending December 31,	Currently Effective	Pro Forma for Class H and Class I Units[1]	Pro Forma for Regency Merger[2]
2015	$86	$31	$91
2016	107	77	142
2017	85	85	145
2018	80	80	140
2019	70	70	130
2020	35	35	50
2021	35	35	35
2022	35	35	35
2023	35	35	35
2024	18	18	18

(1) Pro forma amounts reflect the IDR subsidies, as adjusted for the pending issuance of additional Class H Units and Class I Units discussed above, as well as distributions on the Class I Units. The issuance of additional Class H Units and Class I Units is expected to close in March 2015.

(2) Pro forma amounts reflect the IDR subsidies, as adjusted for (i) the pending issuance of additional Class H Units and Class I Units (as described in Note (1) above) and (ii) the pending Regency Merger. Amounts reflected above assume that the Regency Merger is closed subsequent to the record date for the first quarter of 2015 distribution payment and prior to the record date for the second quarter 2015 distribution payment.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

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 ETP 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).

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

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	Years Ended December 31,				
	2014	2013	2012	2011	2010
Statement of Operations Data:					
Total revenues	$51,158	$46,339	$15,702	$6,799	$5,843
Operating income	2,475	1,541	1,394	1,247	1,065
Income from continuing operations	1,489	735	1,757	700	623
Basic income (loss) from continuing operations per Common Unit	1.58	(0.23)	4.93	1.12	1.23
Diluted income (loss) from continuing operations per Common Unit	1.58	(0.23)	4.91	1.12	1.23
Cash distributions per unit	3.86	3.61	3.58	3.58	3.58
Balance Sheet Data (at period end):					
Total assets	48,221	43,702	43,230	15,519	12,150
Long-term debt, less current maturities	18,332	16,451	15,442	7,388	6,405
Total equity	18,264	16,288	17,332	6,350	4,743
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	343	343	313	134	99
Growth (accrual basis)	4,135	2,112	2,736	1,350	1,276
Cash paid for acquisitions	1,562	1,737	1,364	1,972	178

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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.

Our consolidated subsidiary, Susser Petroleum Partners LP, changed its name in October 2014 to Sunoco LP. Additionally, Trunkline LNG Company, LLC, a consolidated subsidiary of ETE, changed its name in September 2014 to Lake Charles LNG Company, LLC. All references to these entities throughout this document reflect the new name of these entities, regardless of whether the disclosure relates to periods or events prior to the dates of the name changes.

Previously, our reportable segments included a separate segment for NGL transportation and services, which has now been combined into our liquids transportation and services segment and includes our operations related to NGL and crude, except for the crude transportation operations that are included in Sunoco Logistics. The liquids transportation and services segment includes the Bakken crude project, for which capital expenditures had previously been reported in the "All other" segment.

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, CrossCountry and ET Rover Pipeline LLC. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- Liquids operations, including NGL transportation, storage and fractionation services primarily through Lone Star.
- Product and crude oil operations, including the following:
  - product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco, Inc., Susser and Sunoco LP.

Recent Developments

Regency Merger

In January 2015, ETP and Regency entered into a definitive merger agreement, as amended on February 18, 2015 (the "Merger Agreement"), pursuant to which Regency will merge with a wholly-owned subsidiary of ETP, with Regency continuing as the surviving entity and becoming a wholly-owned subsidiary of ETP (the "Regency Merger"). At the effective time of the Regency Merger (the "Effective Time"), each Regency common unit and Class F unit will be converted into the right to receive 0.4066 ETP Common Units, plus a number of additional ETP Common Units equal to $0.32 per Regency common unit divided by the lesser of (i) the volume weighted average price of ETP Common Units for the five trading days ending on the third trading day immediately preceding the Effective Time and (ii) the closing price of ETP Common Units on the third trading day immediately preceding the Effective Time, rounded to the nearest ten thousandth of a unit. Each Regency series A preferred unit will be converted into the right to receive a preferred unit representing a limited partner interest in ETP, a new class of units in ETP to be established at the Effective Time. The transaction is subject to other customary closing conditions including approval by Regency's unitholders.

In addition, ETE, which owns the general partner and 100% of the incentive distribution rights of both Regency and ETP, has agreed to reduce the incentive distributions it receives from ETP by a total of $320 million over a five year period. The IDR subsidy will be $80 million in the first year post closing and $60 million per year for the following

four years. The transaction is expected to close in the second quarter of 2015.

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Bakken Pipeline Transaction

In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline (collectively, the "Bakken pipeline project"), and $879 million in cash (less amounts funded prior to closing by ETE for capital expenditures for the Bakken pipeline project) in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016. This transaction is expected to close in March 2015.

Acquisition of West Texas Gulf by Sunoco Logistics

In December 2014, Sunoco Logistics acquired an additional 28.3% ownership interest in the West Texas Gulf Pipe Line Company from Chevron Pipe Line Company, increasing its controlling financial interest in the consolidated subsidiary to 88.6%. The remaining 11.4% was acquired from Southwest Pipeline Holding Company, LLC in January 2015.

Lone Star NGL Pipeline and Conversion Project

In November 2014, ETP and Regency announced that Lone Star will construct a 533 mile, 24- and 30-inch NGL pipeline from the Permian Basin to Mont Belvieu, Texas and convert Lone Star's existing West Texas 12-inch NGL pipeline into crude oil/condensate service. The new pipeline and conversion projects, estimated to cost between $1.5 billion and $1.8 billion, are expected to be operational by the third quarter of 2016 and the first quarter of 2017, respectively.

Gathering and Processing Construction Projects

In November 2014, ETP announced its plans to construct two new 200 MMcf/d cryogenic gas processing plants and associated gathering systems in the Eagle Ford and Eaglebine production areas. ETP expects to have the first plant online by June 2015 and the second plant by the fourth quarter of 2015.

Lone Star Fractionator

In November 2014, ETP and Regency announced that Lone Star will construct a third natural gas liquids fractionator at its facility in Mont Belvieu, Texas, which will bring Lone Star's total fractionation capacity at Mont Belvieu to 300,000 Bbls/d. Lone Star's third fractionator is scheduled to be operational by December 2015.

Phillips 66 Joint Ventures

In October 2014, ETE, ETP and Phillips 66 formed two joint ventures to develop the previously announced Dakota Access Pipeline ("DAPL") and Energy Transfer Crude Oil Pipeline ("ETCOP") projects. ETP and ETE hold an aggregate interest of 75% in each joint venture and ETP operates both pipeline systems. Phillips 66 owns the remaining 25% interests and funds its proportionate share of the construction costs. The DAPL and ETCOP projects are expected to begin commercial operations in the fourth quarter of 2016.

ET Rover

In June 2014, ETP announced a natural gas pipeline project (now called "Rover") to connect Marcellus and Utica shale supplies to markets in the Midwest, Great Lakes, and Gulf Coast regions of the United States and Canada. ETP has secured multiple, long-term binding shipper agreements on Rover. As a result of these binding agreements, the pipeline is substantially subscribed with 15- and 20-year fee-based contracts to transport up to 3.25 Bcf/d of capacity. Also, ETP recently announced that AE–Midco Rover, LLC ("AE–Midco"), has exercised its option to increase its equity ownership interest in Rover. As a result, AE–Midco (and an affiliate of AE–Midco) will own 35% of Rover and ETP will own 65%.

MACS to Sunoco LP

In October 2014, Sunoco LP acquired MACS from a subsidiary of ETP in a transaction valued at approximately $768 million (the "MACS Transaction"). The transaction included approximately 110 company-operated retail convenience stores and 200 dealer-operated and consignment sites from MACS, which had originally been acquired by ETP in October 2013. The consideration paid by Sunoco LP consisted of approximately 4 million Sunoco LP common units issued to ETP and $556 million in cash, subject to customary closing adjustments. Sunoco LP initially financed the

cash portion by utilizing availability under its revolving credit facility. In October 2014 and November 2014, Sunoco LP partially repaid borrowings on its revolving credit facility with aggregate net proceeds of $405 million from a public offering of 9.1 million Sunoco LP common units.

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Lake Charles LNG Transaction

In February 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, 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. The results of Lake Charles LNG's operations have not been presented as discontinued operations and Lake Charles LNG's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements due to the expected continuing involvement among the entities.

In connection with ETE's acquisition of Lake Charles LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles 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, as discussed further in Note 8 to our consolidated financial statements.

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 significantly 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, 2014 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.

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

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

- Interstate 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.

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

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

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

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

- Investment in Sunoco Logistics – Revenues are generated by charging tariffs for transporting 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 30 states, primarily on the east coast and in the southern regions of the United States. These stores complement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products.

Trends and Outlook

We continue to evaluate and execute strategies to enhance unitholder value through growth, as well as the integration and optimization of our diversified asset portfolio. We intend to continue our distribution rate increases, with a goal of 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.

Crude oil and NGL prices have declined sharply in recent months. As crude oil prices have dropped, the spread between the price of crude oil and natural gas has narrowed, resulting in lower natural gas processing margins, which we expect will be challenging primarily for the midstream segment. Our intrastate and interstate transportation and storage are not significantly supported by such price movements. However, our retail marketing operations have benefited from such declines, as retail margins improve during periods of declining commodity prices. In addition, crude oil and NGLs are currently in contango, which should benefit our liquids storage operations.

We expect crude oil and NGLs to remain challenged for several years due to general oversupply. The addition of several ethane crackers and export projects (Marcus Hook and Nederland) currently under construction will help to balance this market by 2018. Other factors such as reduced wet gas extraction will also help to balance this market and positively impact prices. Natural gas pricing is expected to remain within a range similar to recent history as increased supply continues to outpace demand. New demand from nuclear power plant de-commissioning, as well as continued coal to gas switching for power generation, will help pricing in the second half of 2015; however, supply is continuing to increase. Natural gas extraction efficiency has been occurring at a very fast pace which helps to reduce the economic breakeven price for drilling each well. In addition to an expectation of ample natural gas supplies, the forward seasonal spreads have also narrowed. This narrowing implies that the market is more confident that ample supply exists in peak demand times.

We believe that we are well-positioned to benefit from changes in natural gas and NGL supply and demand fundamentals. While we continue to increase our presence in domestic producing basins, we have also recently focused on projects that will position the Partnership as a leader in the export of hydrocarbons. In particular, we currently are undertaking projects involving natural gas exports, including the Rover pipeline project, and waterborne NGL exports, as well as our participation in the Lake Charles LNG liquefaction project. We are also developing the Bakken pipeline project to transport crude supply from the Bakken/Three Forks production area.

We also continue to seek 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. During 2015, we expect to continue to drop down our retail business into our subsidiary, Sunoco LP, with the ultimate goal of migrating all of our retail business.

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. Upon completion of our pending merger with Regency, we expect to capitalize on the full breadth of the combined gathering and processing platforms, and we also believe that the merger is likely to provide volume growth among our legacy businesses. In addition, we expect the merger to provide substantial cost savings.

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

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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.

In accordance with GAAP, we have accounted for the ETP 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).

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Consolidated Results

	Years Ended December 31,		
	2014	2013	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$500	$464	$36
Interstate transportation and storage	1,110	1,269	(159)
Midstream	608	479	129
Liquids transportation and services	591	351	240
Investment in Sunoco Logistics	971	871	100
Retail marketing	731	325	406
All other	318	194	124
Total	4,829	3,953	876
Depreciation and amortization	(1,130)	(1,032)	(98)
Interest expense, net of interest capitalized	(860)	(849)	(11)
Gain on sale of AmeriGas common units	177	87	90
Goodwill impairment	—	(689)	689
Gains (losses) on interest rate derivatives	(157)	44	(201)
Non-cash unit-based compensation expense	(58)	(47)	(11)
Unrealized gains on commodity risk management activities	23	51	(28)
Inventory valuation adjustments	(473)	3	(476)
Non-operating environmental remediation	—	(168)	168
Adjusted EBITDA related to discontinued operations	(27)	(76)	49
Adjusted EBITDA related to unconsolidated affiliates	(674)	(629)	(45)
Equity in earnings of unconsolidated affiliates	234	172	62
Other, net	(40)	12	(52)
Income from continuing operations before income tax expense	1,844	832	1,012
Income tax expense from continuing operations	(355)	(97)	(258)
Income from continuing operations	1,489	735	754
Income from discontinued operations	64	33	31
Net income	$1,553	$768	$785

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions, partially offset by a decrease in depreciation and amortization of $39 million related to the Lake Charles LNG Transaction.

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Gain on Sale of AmeriGas Common Units. During the year ended December 31, 2014 and 2013, we sold 18.9 million and 7.5 million, respectively, of the AmeriGas common units that were 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. As of December 31, 2014, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Goodwill Impairment. In 2013, Lake Charles 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 Lake Charles 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 Lake Charles LNG reporting unit was less than its carrying amount.

Gains (Losses) on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives during the year ended December 31, 2014 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value. Conversely, increases in forward interest rates resulted in gains on interest rate derivatives during the year ended December 31, 2013.

Unrealized Gains on Commodity Risk Management Activities. See discussion of the unrealized gains on commodity risk management activities included in "Segment Operating Results" below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco Logistics' crude oil and products inventories and our retail marketing operations as a result of commodity price changes between periods.

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

Adjusted EBITDA Related to Discontinued Operations. In 2014, amounts were related to a marketing business that was sold effective April 1, 2014. In 2013, amounts were primarily related to Southern Union's local distribution operations.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. See additional information in "Supplemental Information on Unconsolidated Affiliates" and "Segment Operation Results" below.

Other, net. Other, net in 2014 primarily includes amortization of regulatory assets and other income and expense amounts. Other, net in 2013 was primarily related to biodiesel tax credits recorded by Sunoco, Inc., amortization of regulatory assets and other income and expense amounts.

Income Tax Expense from Continuing Operations. Income tax expense is based on the earnings of our taxable subsidiaries. In addition, the year ended December 31, 2014 included the impact of the Lake Charles LNG Transaction, which was treated as a sale for tax purposes, resulting in $76 million of incremental income tax expense.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2014	2013	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$96	$87	$9
FEP	55	55	—
Regency	(19)	8	(27)
PES	59	(48)	107
AmeriGas	21	50	(29)
Other	22	20	2
Total equity in earnings of unconsolidated affiliates	$234	$172	$62
Adjusted EBITDA related to unconsolidated affiliates[(1)]:			
Citrus	$305	$296	$9
FEP	75	75	—
Regency	100	66	34
PES	86	(30)	116
AmeriGas	56	175	(119)
Other	52	47	5
Total Adjusted EBITDA related to unconsolidated affiliates	$674	$629	$45
Distributions received from unconsolidated affiliates:			
Citrus	$168	$175	$(7)
FEP	70	69	1
Regency	61	44	17
PES	—	65	(65)
AmeriGas	22	86	(64)
Other	27	25	2
Total distributions received from unconsolidated affiliates	$348	$464	$(116)

(1) These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates and are based on our equity in earnings or losses of our unconsolidated affiliates adjusted for our proportionate share of the unconsolidated affiliates' interest, depreciation, amortization, non-cash items and taxes.

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 and our natural gas marketing operations.

In 2014, 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.

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.

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

- Gross margin, operating expenses, and selling, general and administrative expenses. 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 and inventory valuation adjustments. 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 15 to our consolidated financial statements.

Intrastate Transportation and Storage

	Years Ended December 31,		
	2014	2013	Change
Natural gas transported (MMBtu/d)	8,976,978	9,455,878	(478,900)
Revenues	$2,857	$2,452	$405
Cost of products sold	2,169	1,737	432
Gross margin	688	715	(27)
Unrealized (gains) losses on commodity risk management activities	21	(39)	60
Operating expenses, excluding non-cash compensation expense	(180)	(188)	8
Selling, general and administrative expenses, excluding non-cash compensation expense	(27)	(24)	(3)
Adjusted EBITDA related to unconsolidated affiliates	(2)	—	(2)
Segment Adjusted EBITDA	$500	$464	$36

Volumes. Transported volumes decreased due to the reduction of volumes under certain long-term transportation contracts offset by increased volumes due to a more favorable pricing environment.

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

	Years Ended December 31,		
	2014	2013	Change
Transportation fees	$466	$491	$(25)
Natural gas sales and other	100	80	20
Retained fuel revenues	98	96	2
Storage margin, including fees	24	48	(24)
Total gross margin	$688	$715	$(27)

Intrastate transportation and storage gross margin decreased for the year ended December 31, 2014 compared to the prior year due to the following:

- Transportation fees. Transportation fees decreased primarily due to the reduction of volumes under certain long-term transportation contracts.
- 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, gains and losses on derivatives used to hedge net retained fuel, and the

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margin from gas sales, processing and gathering fees on our Houston pipeline system. Margin from natural gas sales and other increased $20 million primarily due to favorable results from our optimization 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 revenue increased slightly as gains due to increased market prices, resulting in an $11 million increase in retention gas sales, were offset by a reduction of $9 million due to lower volumes resulting from the cessation of certain long-term contracts. The average spot price at the Houston Ship Channel location for the year ended December 31, 2014 increased by $0.62/MMBtu, or 17%, to $4.31/MMBtu compared to $3.69/MMBtu in the prior year. Retained fuel volumes were down 9% from year to year.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2014	2013	Change
Withdrawals from storage natural gas inventory (MMBtu)	37,197,510	36,962,300	235,210
Realized margin on natural gas inventory transactions	$17	$(16)	$33
Fair value inventory adjustments	(54)	28	(82)
Unrealized gains on derivatives	35	8	27
Margin recognized on natural gas inventory, including related derivatives	(2)	20	(22)
Revenues from fee-based storage	27	28	(1)
Other costs	(1)	—	(1)
Total storage margin	$24	$48	$(24)

The decrease in 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 resulting in a $14 million reduction in margin from year to year. The remainder of the decrease was primarily due to non-cash mark-to-market losses of $8 million on hedges for future storage seasons.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized gains and losses on commodity risk management activities reflect the net impact from storage and non-storage derivatives, as well as fair value adjustments to inventory. We experienced a decrease of $60 million in the margin from unrealized gains and losses on commodity risk management activities in the year ended December 31, 2014 as compared to the prior year. For 2014, unrealized losses from commodity risk management activities of $21 million consisted of losses of $54 million on the fair value adjustment to hedged storage gas inventory offset by unrealized gains of $33 million on unrealized storage and non-storage related derivatives. Unrealized losses from storage related activities were primarily offset by realized margin on natural gas inventory transaction as illustrated in the storage margin table above. For 2013, unrealized gains from commodity risk management activities of $39 million consisted of unrealized gains from storage and non-storage related derivatives of $12 million and unrealized gains from fair value adjustments to storage gas inventory of $28 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased for the year ended December 31, 2014 compared to the prior year primarily due to a decrease in ad valorem taxes driven by the settlement of lower valuation with local taxing authorities during the period.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses increased for the year ended December 31, 2014 compared to the prior year primarily due to higher employee-related costs.

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Interstate Transportation and Storage

	Years Ended December 31,		
	2014	2013	Change
Natural gas transported (MMBtu/d)	6,163,372	6,428,574	(265,202)
Natural gas sold (MMBtu/d)	16,470	18,835	(2,365)
Revenues	$1,072	$1,309	$(237)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(291)	(332)	41
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(62)	(80)	18
Adjusted EBITDA related to unconsolidated affiliates	380	372	8
Other	11	—	11
Segment Adjusted EBITDA	$1,110	$1,269	$(159)

Volumes. For the year ended December 31, 2014 compared to the prior year, transported volumes decreased due to lower volumes transported on the Tiger pipeline resulting from decreased production from the Haynesville Shale and due to lower utilization on the Trunkline and Transwestern pipelines. The decreases in volumes on the Tiger, Trunkline and Transwestern pipelines were partially offset by higher volumes transported on the Panhandle pipeline due to increased demand resulting from the cold winter season during the first quarter of 2014.

Revenues. The decrease in volumes transported, as discussed above, did not significantly impact revenues, which are primarily fixed fees for the reservation of capacity on the pipelines. Interstate transportation and storage revenues decreased for the year ended December 31, 2014 compared to the prior year primarily due to a $216 million reduction from the deconsolidation of Lake Charles LNG effective January 1, 2014 and the recognition in 2013 of $52 million received in connection with the buyout of a customer contract. These decreases were partially offset by an increase of approximately $29 million due to capacity sold at higher rates and loan related activity from higher basis differentials and spot prices resulting from the colder weather, primarily during the first quarter of 2014 on the Panhandle pipeline.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Interstate transportation and storage operating expenses decreased for the year ended December 31, 2014 compared to the prior year primarily due to the deconsolidation of Lake Charles LNG effective January 1, 2014.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage selling, general and administrative expenses decreased for the year ended December 31, 2014 compared to the prior year due to a decrease of $9 million from the deconsolidation of Lake Charles LNG, a decrease of $7 million in professional fees, and a decrease of $2 million in employee-related costs.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased for the year ended December 31, 2014 compared to the prior year primarily due to increased earnings from Citrus as a result of the sale of additional capacity and lower operating expenses due to lower ad valorem taxes.

Other. Other includes the recognition of an $11 million keep-whole payment received from our FEP joint venture partner.

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Midstream

	Years Ended December 31,		
	2014	2013	Change
Gathered volumes (MMBtu/d)[1]	2,983,149	2,462,677	520,472
NGLs produced (Bbls/d)[1]	173,603	111,226	62,377
Equity NGLs (Bbls/d)[1]	13,989	11,849	2,140
Revenues	$2,923	$2,249	$674
Cost of products sold	2,174	1,579	595
Gross margin	749	670	79
Unrealized gains on commodity risk management activities	—	(7)	7
Operating expenses, excluding non-cash compensation expense	(121)	(159)	38
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(28)	8
Other	—	3	(3)
Segment Adjusted EBITDA	$608	$479	$129

[1] Excludes Southern Union's gathering and processing operations which were deconsolidated on April 30, 2013.

Volumes. Gathered volumes, NGL produced and equity NGLs increased for the year ended December 31, 2014 compared to the prior year primarily due to increased production by our customers in the Eagle Ford Shale and the Permian Basin. We brought into service 320 MMcf/d in additional processing capacity during the year ended December 31, 2014.

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

	Years Ended December 31,		
	2014	2013	Change
Gathering and processing fee-based revenues	$570	$449	$121
Non fee-based contracts and processing	179	221	(42)
Total gross margin	$749	$670	$79

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

- Gathering and processing fee-based revenues. Increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale resulted in increased fee-based revenues of $121 million for the year ended December 31, 2014 compared to the prior year. In addition, fee-based margin also increased $7 million due to a change in contract terms on our Southeast Texas system where certain contracts were converted from non fee-based terms to fee-based. These increases were partially off set by a decrease of $8 million due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.
- Non fee-based contracts and processing margin. For the year ended December 31, 2014 compared to the prior year, non fee-based margins reflected a decrease of $36 million due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013 and a decrease of $12 million on our Southeast Texas system due to changes in contract mix as a result of converting certain non fee-based contracts into long-term fee-based contracts. These decreases were partially offset by an increase of $5 million in non fee-based margin from our Eagle Ford system, primarily due to higher equity volumes.

Unrealized Gains on Commodity Risk Management Activities. Our midstream segment recorded unrealized gains associated with hedges that were de-designated during the prior year.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses decreased for the year ended December 31, 2014 compared to the prior year primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased for the year ended December 31, 2014 compared to the prior year primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.

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Liquids Transportation and Services

	Years Ended December 31,		
	2014	2013	Change
Liquids transportation volumes (Bbls/d)	379,342	270,609	108,733
NGL fractionation volumes (Bbls/d)	197,415	101,967	95,448
Revenues	$3,911	$2,127	$1,784
Cost of products sold	3,166	1,655	1,511
Gross margin	745	472	273
Unrealized gains on commodity risk management activities	(12)	(1)	(11)
Operating expenses, excluding non-cash compensation expense	(128)	(109)	(19)
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(16)	(4)
Adjusted EBITDA related to unconsolidated affiliates	6	5	1
Segment Adjusted EBITDA	$591	$351	$240

Volumes. The increase in liquids transportation volumes for the year ended December 31, 2014 compared to the prior year reflected an increase of approximately 109,000 Bbls/d in volumes transported on our wholly-owned and joint venture NGL pipelines due to an increase in production for our Jackson processing plant and volumes transported to our Mont Belvieu, Texas facilities via our Justice pipeline. The remainder of the increase was from volumes transported on our Lone Star pipeline system primarily out of west Texas.

Average daily fractionated volumes increased for the year ended December 31, 2014 compared to the prior year primarily due to the recent commissioning of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas. These volumes include all physical and contractual volumes where we collected a fractionation fee.

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

	Years Ended December 31,		
	2014	2013	Change
Transportation margin	$312	$187	$125
Processing and fractionation margin	247	142	105
Storage margin	157	137	20
Other margin	29	6	23
Total gross margin	$745	$472	$273

For the year ended December 31, 2014 compared to prior year, liquids transportation and services segment gross margin increased due to the following:

- Transportation margin. Transportation margin increased $69 million due to higher volumes transported from west Texas and the Eagle Ford Shale on our Lone Star pipeline system and $56 million due to increases in NGL production from our processing plants that connect to various fractionators via our wholly-owned pipelines.
- Processing and fractionation margin. Processing and fractionation margin increased $117 million due to the startup of Lone Star's second fractionator at Mont Belvieu, Texas in October 2013. This increase was partially offset by a $12 million decrease in margin attributable to our fractionator in Geismar, Louisiana, where margin was affected by the combined impacts from a less rich refinery off-gas feed and lower overall production volumes through the facility following the expiration of a major supplier contract in June 2013.
- Storage margin. Storage margin increased approximately $13 million due to increased throughput activity. The remainder of the increase in storage margin was primarily due to increased blending and other non fee-based storage activities.
- Other margin. Other margin increased approximately $23 million due to increased commercial optimization activities related to our fractionators, primarily due to the recent commissioning of our second fractionator at Mont Belvieu, Texas and the optimization of available storage capacity at our Mont Belvieu facilities.

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Operating Expenses, Excluding Non-Cash Compensation Expense. Liquids transportation and services operating expenses increased for the year ended December 31, 2014 compared to the prior year primarily due to the start-up of Lone Star's second fractionator in Mont Belvieu, Texas in October 2013.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Liquids transportation and services selling, general and administrative expenses increased for the year ended December 31, 2014 compared to the prior year primarily due to an increase in employee-related costs.

Investment in Sunoco Logistics

	Years Ended December 31,		
	2014	2013	Change
Revenue	$18,088	$16,639	$1,449
Cost of products sold	17,110	15,574	1,536
Gross margin	978	1,065	(87)
Unrealized gains on commodity risk management activities	(17)	(1)	(16)
Operating expenses, excluding non-cash compensation expense	(192)	(148)	(44)
Selling, general and administrative expenses, excluding non-cash compensation expense	(107)	(79)	(28)
Inventory valuation adjustments	258	—	258
Adjusted EBITDA related to unconsolidated affiliates	49	41	8
Other	2	(7)	9
Segment Adjusted EBITDA	$971	$871	$100

Segment Adjusted EBITDA. For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $28 million from crude oil pipelines, primarily due to an increase of $69 million from higher throughput volumes largely attributable to expansion projects placed in service, partially offset by lower average pipeline revenue per barrel of $9 million and higher operating expenses of $29 million, which included lower pipeline operating gains, higher environmental remediation costs, increased pipeline maintenance costs and higher costs associated with growth projects;
- an increase of $113 million from terminal facilities, primarily from an increase of $101 million due to higher volumes and increased margins from refined products and NGLs acquisition and marketing activities and $16 million related to improved contributions from Sunoco Logistics' bulk marine terminals, partially offset by a decrease of $4 million due to lower volumes at Sunoco Logistics' refined products terminals; and
- an increase of $29 million from products pipelines, primarily due to higher average pipeline revenue per barrel of $50 million, which was largely driven by Sunoco Logistics' Mariner West project, and higher contributions from Sunoco Logistics' joint venture interests of $8 million, partially offset by increased costs attributable to growth projects of $30 million; partially offset by
- a decrease of $70 million from crude oil acquisition and marketing activities primarily due to lower crude oil margins of $106 million driven by contracted crude differentials and higher costs of $5 million associated with growth projects, partially offset by a $42 million increase in crude oil volumes resulting from higher market demand, expansion of the crude oil trucking fleet, and recent acquisitions.

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Retail Marketing

	Years Ended December 31,		
	2014	2013	Change
Retail gasoline outlets, end of period:			
Total	6,650	5,112	1,538
Company-operated	1,251	513	738
Motor fuel sales:			
Total gallons (in millions)	6,382	5,456	926
Company-operated (gallons/month per site)	177,236	200,087	(22,851)
Motor fuel gross profit (cents per gallon):			
Total	15.0	10.1	4.9
Company-operated	31.2	25.5	5.7
Merchandise sales	$1,091	$543	$548
Revenue	$22,487	$21,012	$1,475
Cost of products sold	21,154	20,150	1,004
Gross margin	1,333	862	471
Unrealized gains on commodity risk management activities	(1)	(1)	—
Operating expenses, excluding non-cash compensation expense	(727)	(473)	(254)
Selling, general and administrative expenses, excluding non-cash compensation expense	(92)	(63)	(29)
Inventory valuation adjustments	215	(3)	218
Adjusted EBITDA related to unconsolidated affiliates	3	4	(1)
Other	—	(1)	1
Segment Adjusted EBITDA	$731	$325	$406

Gross Margin. For the year ended December 31, 2014 compared to the prior year, retail marketing gross margin included a favorable impact of $335 million from the acquisition of Susser in August 2014 and $158 million from other recent acquisitions, including the MACS acquisition in October 2013. Retail marketing gross margin also increased $136 million from strong retail gasoline and diesel margins and $60 million due to favorable results in non-retail margins. These increases were partially offset by unfavorable impacts of $218 million related to non-cash inventory valuation adjustments.

Operating Expenses, Excluding Non-Cash Compensation Expense. Retail marketing operating expenses increased for the year ended December 31, 2014 compared to the prior year primarily due to recent acquisitions.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Retail marketing selling, general and administrative expenses increased for the year ended December 31, 2014 compared to the prior year primarily due to recent acquisitions.

Inventory Valuation Adjustments. Retail marketing recorded inventory valuation reserve adjustments as a result of commodity price changes between periods.

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All Other

	Years Ended December 31,		
	2014	2013	Change
Revenue	$2,394	$2,367	$27
Cost of products sold	2,338	2,309	29
Gross margin	56	58	(2)
Unrealized gains on commodity risk management activities	(14)	(2)	(12)
Operating expenses, excluding non-cash compensation expense	(5)	(31)	26
Selling, general and administrative expenses, excluding non-cash compensation expense	(58)	(106)	48
Adjusted EBITDA related to discontinued operations	27	76	(49)
Adjusted EBITDA related to unconsolidated affiliates	244	213	31
Other	73	(4)	77
Elimination	(5)	(10)	5
Segment Adjusted EBITDA	$318	$194	$124

Amounts reflected in our all other segment during the periods presented primarily included:

- our natural gas marketing and compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture; and
- our investment in Regency common and Class F units, which were received by Southern Union (now Panhandle) in exchange for the contribution of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013; and
- our investment in AmeriGas until August 2014.

For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA increased due to the net impact of the following:

- an increase of $75 million in management fees, as further described below;
- a favorable impact of approximately $47 million due to costs associated with certain Sunoco activities that were included in the all other Segment Adjusted EBITDA in the prior year;
- favorable results from our natural gas marketing business of $15 million;
- an increase of $31 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to higher earnings from our investment in Regency of $34 million, including the impact of only recording a partial period of earnings from Regency beginning on April 30, 2013, and higher earnings from our investment in PES of $116 million, partially offset by a decrease of $119 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2013 and 2014;
- a refund of insurance premiums of $6 million included in the year ended December 31, 2014; and
- Southern Union corporate expenses of $14 million that were no longer included in the all other segment subsequent to the merger of Southern Union, PEPL Holdings and Panhandle in January 2014; offset by
- the recognition of $25 million in merger related costs related to the Susser Merger in the year ended December 31, 2014; and
- a decrease in Adjusted EBITDA related to discontinued operations of $49 million primarily due to the sale of Southern Union’s local distribution operations in 2013.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG’s regasification facility and the development of a liquefaction project at Lake Charles 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. These fees were reflected in “Other” in the “All other” segment and for the year ended December 31, 2014 were reflected as an offset to operating expenses of $25 million and selling, general and administrative expenses of $50 million in the consolidated statements of operations.

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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
Liquids 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
Inventory 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, Inc. of $113 million in 2013 compared to $32 million from October 5, 2012 through December 31, 2012; and

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- 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, Inc. 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, Lake Charles 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 Lake Charles 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 Lake Charles 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 of the unrealized gains (losses) on commodity risk management activities included in "Segment Operating Results" below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with our 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, Inc.'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, Inc., 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.

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

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2013	2012	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$87	$65	$22
FEP	55	55	—
Regency	8	—	8
PES	(48)	24	(72)
AmeriGas	50	(4)	54
Other	20	2	18
Total equity in earnings of unconsolidated affiliates	$172	$142	$30
Adjusted EBITDA related to unconsolidated affiliates:			
Citrus	$296	$228	$68
FEP	75	77	(2)
Regency	66	—	66
PES	(30)	26	(56)
AmeriGas	175	139	36
Other	47	10	37
Total Adjusted EBITDA related to unconsolidated affiliates	$629	$480	$149
Distributions received from unconsolidated affiliates:			
Citrus	$175	$88	$87
FEP	69	70	(1)
Regency	44	—	44
PES	65	—	65
AmeriGas	86	94	(8)
Other	25	10	15
Total distributions received from unconsolidated affiliates	$464	$262	$202

Segment Operating Results

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	(188)	(190)	2
Selling, general and administrative, excluding non-cash compensation expense	(24)	(26)	2
Adjusted EBITDA related to unconsolidated affiliates	—	1	(1)
Segment Adjusted EBITDA	$464	$601	$(137)

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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.

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

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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.

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	(332)	(256)	(76)
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(80)	(144)	64
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	2,462,677	2,364,133	98,544
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 (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	(159)	(151)	(8)
Selling, general and administrative, excluding non-cash compensation expense	(28)	(70)	42
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 NGLs 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	221	341	(120)
Total gross margin	$670	$680	$(10)

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 $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.

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.

Liquids Transportation and Services

	Years Ended December 31,		
	2013	2012	Change
Liquids transportation volumes (Bbls/d)	270,609	172,569	98,040
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	(109)	(63)	(46)
Selling, general and administrative expenses, excluding non-cash compensation expense	(16)	(17)	1
Adjusted EBITDA related to unconsolidated affiliates	5	—	5
Segment Adjusted EBITDA	$351	$209	$142

Volumes. Liquids 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 liquids 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, liquids 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.
- 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

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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. Liquids transportation and services operating expenses increased primarily due to additional expenses from assets recently placed in service.

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	(148)	(58)	(90)
Selling, general and administrative expenses, excluding non-cash compensation expense	(79)	(22)	(57)
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, Inc.; 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.

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Retail Marketing

	Years Ended December 31,		
	2013	2012	Change
Retail gasoline outlets, end of period:			
Total	5,112	4,988	124
Company-operated	513	437	76
Motor fuel sales:			
Total gallons (in millions)	5,456	1,474	3,982
Company-operated (gallons/month per site)	200,087	198,000	2,087
Motor fuel gross profit (cents per gallon):			
Total	10.1	12.5	(2.4)
Company-operated	25.5	31.0	(5.5)
Merchandise sales	$543	$125	$418
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	(473)	(130)	(343)
Selling, general and administrative expenses, excluding non-cash compensation expense	(63)	(6)	(57)
Inventory 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, Inc.; 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. Segment Adjusted EBITDA 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

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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 marketing and compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture, effective upon our acquisition of Sunoco, Inc. on October 5, 2012; and
- our investment in Regency common and Class F units, which were received by Southern Union in exchange of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013.

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."

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 ETP Holdco Transaction for the year ended December 31, 2012, giving effect that it occurred on January 1, 2012. 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 ETP Holdco Transaction had been consummated on January 1, 2012.

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

	ETP Historical	Propane Transaction[a]	Sunoco, Inc. Historical[b]	Southern Union Historical[c]	ETP 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

[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 ETP 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.

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- 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 recorded in Southern Union's historical income statements.
- 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 2015 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage	$30	$40	$30	$35
Interstate transportation and storage[2]	1,000	1,100	125	130
Midstream	550	650	10	15
Liquids transportation and services[2][3]	2,500	2,600	20	25
Retail marketing[4]	185	235	80	100
All other (including eliminations)	20	25	10	20
Total direct capital expenditures	4,285	4,650	275	325
Indirect[1]:				
Investment in Sunoco Logistics	1,800	2,200	70	90
Investment in Sunoco LP[4]	165	215	15	25
Total indirect capital expenditures	1,965	2,415	85	115
Total projected capital expenditures	$6,250	$7,065	$360	$440

(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiaries; all other capital expenditures are reflected as direct capital expenditures.

(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipeline projects.

(3) Includes 100% of Lone Star's capital expenditures. We expect to receive capital contributions from Regency related its 30% interest in Lone Star of between $350 million and $400 million.

(4) The retail marketing segment includes the investment in Sunoco LP, as well as ETP's wholly-owned retail marketing operations. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

The assets used in our natural gas and liquids 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, 2014, in addition to $639 million of cash on hand, we had available capacity under the ETP Credit Facility of $1.81 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 2015; however, we

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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, 2014, Sunoco Logistics had available borrowing capacity of $1.35 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.

Sunoco LP's primary sources of liquidity consist of cash generated from operating activities and borrowings under its $1.25 billion credit facility. At December 31, 2014, Sunoco LP had available borrowing capacity of $567 million under its revolving credit facility.

Cash Flows

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions, and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense 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, 2014

Cash provided by operating activities in 2014 was $2.56 billion and net income was $1.55 billion. The difference between net income and cash provided by operating activities in 2014 primarily consisted of non-cash items totaling $1.08 billion offset by net changes in operating assets and liabilities of $264 million. The non-cash activity in 2014 consisted primarily of depreciation and amortization of $1.13 billion and inventory valuation adjustments of $473 million offset slightly by the gain on the sale of AmeriGas common units of $177 million.

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 $99 million. 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.

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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, 2014

Cash used in investing activities in 2014 was $4.60 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $4.11 billion. Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $1.56 billion for acquisitions, primarily for the Susser Merger and the acquisition of a noncontrolling interest. In addition, we received $814 million in cash from sale of AmeriGas common units.

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 ETP 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, Inc. We also received net cash proceeds of $1.44 billion from the contribution of the Propane Business.

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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, 2014:					
Direct[1]:					
Intrastate transportation and storage	$133	$36	$169	$(19)	$150
Interstate transportation and storage	301	110	411	(126)	285
Midstream	652	15	667	(40)	627
Liquids transportation and services[2]	406	21	427	(15)	412
Retail marketing[3]	104	73	177	1	178
All other (including eliminations)	28	7	35	(20)	15
Total direct capital expenditures	1,624	262	1,886	(219)	1,667
Indirect[1]:					
Investment in Sunoco Logistics	2,434	76	2,510	(146)	2,364
Investment in Sunoco LP[3]	77	5	82	—	82
Total indirect capital expenditures	2,511	81	2,592	(146)	2,446
Total capital expenditures	$4,135	$343	$4,478	$(365)	$4,113
Year Ended December 31, 2013:					
Direct[1]:					
Intrastate transportation and storage	$18	$29	$47	$(3)	$44
Interstate transportation and storage	55	97	152	18	170
Midstream	516	49	565	87	652
Liquids transportation and services	426	17	443	84	527
Retail marketing	113	63	176	(1)	175
All other (including eliminations)	19	35	54	4	58
Total direct capital expenditures	1,147	290	1,437	189	1,626
Indirect[1]:					
Investment in Sunoco Logistics	965	53	1,018	(121)	897
Total indirect capital expenditures	965	53	1,018	(121)	897
Total capital expenditures	$2,112	$343	$2,455	$68	$2,523
Year Ended December 31, 2012:					
Direct[1]:					
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
Liquids transportation and services	1,288	14	1,302	(75)	1,227
Retail marketing	38	20	58	(19)	39
All other (including eliminations)	14	49	63	—	63
Total direct capital expenditures	2,618	292	2,910	(244)	2,666
Indirect[1]:					
Investment in Sunoco Logistics	118	21	139	—	139
Total indirect capital expenditures	118	21	139	—	139
Total capital expenditures	$2,736	$313	$3,049	$(244)	$2,805

(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiaries; all other capital expenditures are reflected as direct capital expenditures.

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(2) Includes 100% of Lone Star's capital expenditures. We received $126 million in capital contributions from Regency related to its 30% interest in Lone Star during the year ended December 31, 2014.

(3) The retail marketing segment includes the investment in Sunoco LP, as well as ETP's wholly-owned retail marketing operations. Capital expenditures incurred by Susser and Sunoco LP are reflected beginning on the acquisition date of August 29, 2014 and are broken out between direct and indirect amounts. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

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.

Following is a summary of financing activities by period:

Year Ended December 31, 2014

Cash provided by financing activities was $2.13 billion in 2014. We received $1.38 billion in net proceeds from Common Unit offerings, and our subsidiaries received $1.24 billion in net proceeds from the issuance of common units. 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 2014, we had a net increase in our debt level of $1.69 billion primarily due to Sunoco Logistics' issuance of $2.00 billion in aggregate principal amount of senior notes in April 2014 and November 2014 (see Note 6 to our consolidated financial statements). In addition, we incurred debt issuance costs of $30 million. In 2014, we paid distributions of $1.96 billion to our partners and we paid distributions of $362 million to noncontrolling interests. In addition, we received capital contributions of $174 million, which were primarily from Regency for its noncontrolling interest in Lone Star.

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.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2014	2013
ETP Senior Notes	$10,890	$11,182
Transwestern Senior Notes	782	870
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	715	965
Sunoco Logistics Senior Notes	3,975	2,150
Revolving credit facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2019	570	65
Sunoco Logistics' subsidiary $35 million Revolving Credit Facility due April 30, 2015	35	35
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 19, 2018	150	200
Sunoco LP $1.25 billion Revolving Credit Facility due September 25, 2019	683	—
Other long-term debt	223	228
Unamortized premiums, net of discounts and fair value adjustments	232	308
Total debt	19,340	17,088
Less: current maturities of long-term debt	1,008	637
Long-term debt, less current maturities	$18,332	$16,451

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.

Sunoco Logistics Senior Notes Offerings

In April 2014, Sunoco Logistics issued $300 million aggregate principal amount of 4.25% senior notes due April 2024 and $700 million aggregate principal amount of 5.30% senior notes due April 2044. In November 2014, Sunoco Logistics issued an additional $200 million under the April 2024 senior notes and $800 million aggregate principal amount of 5.35% senior notes due May 2045. Sunoco Logistics' used the net proceeds from the offerings to pay borrowings under the Sunoco Logistics Credit Facility and for general partnership purposes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2019. 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. In February 2015, ETP amended its revolving credit facility to increase the capacity to $3.75 billion.

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

As of December 31, 2014, the ETP Credit Facility had $570 million outstanding, and the amount available for future borrowings was $1.81 billion after taking into account letters of credit of $121 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 1.66%.

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Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $1.50 billion unsecured credit facility (the "Sunoco Logistics Credit Facility") which matures in November 2018. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions.

The Sunoco Logistics Credit Facility is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The Sunoco Logistics Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. As of December 31, 2014, the Sunoco Logistics Credit Facility had $150 million of outstanding borrowings.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, maintains 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. At December 31, 2014, this credit facility had $35 million of outstanding borrowings.

Sunoco LP Credit Facility

In September 2014, Sunoco LP entered into a $1.25 billion revolving credit agreement (the "Sunoco LP Credit Facility"), which matures in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of December 31, 2014, the Sunoco LP Credit Facility had $683 million of outstanding borrowings.

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.

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, 2014.

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."

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Covenants Related to Panhandle

Panhandle 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 Panhandle's lending agreements. Financial covenants exist in certain of Panhandle's debt agreements that require Panhandle 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 Panhandle 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 Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle'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 Panhandle's debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle 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 Panhandle's cash management program; and limitations on Panhandle'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 3.7 to 1 at December 31, 2014, as calculated in accordance with the credit agreements.

The West Texas Gulf Pipeline Company's $35 million credit facility limits West Texas Gulf, on a rolling four-quarter basis, to a minimum fixed charge coverage ratio of 1.00 to 1. 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 1.67 to 1 and 0.85 to 1, respectively, at December 31, 2014.

Covenants Related to Sunoco LP

The Sunoco LP Credit Facility requires Sunoco LP to maintain a leverage ratio of not more than 5.50 to 1. The maximum leverage ratio is subject to upwards adjustment of not more than 6.00 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in an acquisition of assets, equity interests, operating lines or divisions by Sunoco LP, a subsidiary, an unrestricted subsidiary or a joint venture for a purchase price of not less than $50 million. Indebtedness under the Sunoco LP Credit Facility is secured by a security interest in, among other things, all of the Sunoco LP's present and future personal property and all of the present and future personal property of its guarantors, the capital stock of its material subsidiaries (or 66% of the capital stock of material foreign subsidiaries), and any intercompany debt. Upon the first achievement by Sunoco LP of an investment grade credit rating, all security interests securing the Sunoco LP Credit Facility will be released.

Compliance with our Covenants

We are required to assess compliance quarterly and were in compliance with all requirements, limitations, and covenants relating to ETP's and its subsidiaries' debt agreements as of December 31, 2014.

Off-Balance Sheet Arrangements

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”).

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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, 2014:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$19,108	$1,050	$1,542	$3,414	$13,102
Interest on long-term debt[1]	13,877	1,041	1,963	1,693	9,180
Payments on derivatives	159	20	83	50	6
Purchase commitments[2]	13,090	7,275	3,168	1,188	1,459
Transportation, natural gas storage and fractionation contracts	89	26	43	20	—
Operating lease obligations	1,392	146	238	205	803
Other[3]	327	174	75	56	22
Total[4]	$48,042	$9,732	$7,112	$6,626	$24,572

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2014. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2014. 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 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, 2014 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 $1.12 billion of total purchase commitments relate to production from PES.

(3) Expected contributions to fund our pension and postretirement benefit plans were included in "Other" above. Environmental liabilities, asset retirement obligations, unrecognized tax benefits, contingency accruals and deferred revenue, which were included in "Other non-current liabilities" our consolidated balance sheets were excluded from the table above as such amounts do not represent contractual obligations or, in some cases, the

amount and/or timing of the cash payments is uncertain.

(4) Excludes non-current deferred tax liabilities of $4.23 billion due to uncertainty of the timing of future cash flows for such liabilities.

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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 during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 7, 2012	February 14, 2012	$0.8938
March 31, 2012	May 4, 2012	May 15, 2012	0.8938
June 30, 2012	August 6, 2012	August 14, 2012	0.8938
September 30, 2012	November 6, 2012	November 14, 2012	0.8938
December 31, 2012	February 7, 2013	February 14, 2013	0.8938
March 31, 2013	May 6, 2013	May 15, 2013	0.8938
June 30, 2013	August 5, 2013	August 14, 2013	0.8938
September 30, 2013	November 4, 2013	November 14, 2013	0.9050
December 31, 2013	February 7, 2014	February 14, 2014	0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550
September 30, 2014	November 3, 2014	November 14, 2014	0.9750
December 31, 2014	February 6, 2015	February 13, 2015	0.9950

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,		
	2014	2013	2012
Limited Partners:			
Common Units held by public	$1,179	$997	$775
Common Units held by ETE	119	268	180
Class H Units held by ETE Holdings	219	105	—
General Partner interest held by ETE	21	20	20
Incentive distributions held by ETE	754	701	529
IDR relinquishments related to previous transactions	(250)	(199)	(90)
Total distributions declared to the partners of ETP	$2,042	$1,892	$1,414

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In connection with transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods based on (i) the currently effective partnership agreement provisions, (ii) the assumed closing of the issuance of additional Class H Units and Class I Units, which is expected to occur in March 2015, and (iii) the assumed closing of the Regency Merger, which is expected to occur in the second quarter of 2015:

Years Ending December 31,	Currently Effective	Pro Forma for Class H and Class I Units[1]	Pro Forma for Regency Merger[2]
2015	$86	$31	$91
2016	107	77	142
2017	85	85	145
2018	80	80	140
2019	70	70	130
2020	35	35	50
2021	35	35	35
2022	35	35	35
2023	35	35	35
2024	18	18	18

(1) Pro forma amounts reflect the IDR subsidies, as adjusted for the pending issuance of additional Class H Units and Class I Units discussed above, as well as distributions on the Class I Units. The issuance of additional Class H Units and Class I Units is expected to close in March 2015.

(2) Pro forma amounts reflect the IDR subsidies, as adjusted for (i) the pending issuance of additional Class H Units and Class I Units (as described in Note (1) above) and (ii) the pending Regency Merger. Amounts reflected above assume that the Regency Merger is closed subsequent to the record date for the first quarter of 2015 distribution payment and prior to the record date for the second quarter 2015 distribution payment.

The amounts reflected above include the relinquishment of $350 million in the aggregate of incentive distributions that would potentially be made to ETE over the first forty fiscal quarters commencing immediately after the consummation of the Susser Merger. Such relinquishments would cease upon the agreement of an exchange of the Sunoco LP general partner interest and the incentive distribution rights between ETE and ETP.

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.

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$0.2725
March 31, 2013	May 9, 2013	May 15, 2013	0.2863
June 30, 2013	August 8, 2013	August 14, 2013	0.3000
September 30, 2013	November 8, 2013	November 14, 2013	0.3150
December 31, 2013	February 10, 2014	February 14, 2014	0.3312
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650
September 30, 2014	November 7, 2014	November 14, 2014	0.3825
December 31, 2014	February 9, 2015	February 13, 2015	0.4000

Sunoco Logistics Unit Split

On May 5, 2014, Sunoco Logistics' board of directors declared a two-for-one split of Sunoco Logistics common units. The unit split resulted in the issuance of one additional Sunoco Logistics common unit for every one unit owned as of the close of business

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on June 5, 2014. The unit split was effective June 12, 2014. All Sunoco Logistics unit and per unit information included in this report is presented on a post-split basis.

The total amounts of Sunoco Logistics distributions declared during the periods 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):

	Years Ended December 31,		
	2014	2013	2012
Limited Partners:			
Common units held by public	$225	$173	$39
Common units held by ETP	100	82	18
General Partner interest held by ETP	10	5	1
Incentive distributions held by ETP	175	117	22
Total distributions declared	$510	$377	$80

Cash Distributions Paid by Sunoco LP

Sunoco LP 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.

Distributions declared by Sunoco LP subsequent to our acquisition on August 29, 2014 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2014	November 18, 2014	November 28, 2014	$0.5457
December 31, 2014	February 17, 2015	February 27, 2015	0.6000

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

	Year Ended December 31, 2014
Limited Partners:	
Common units held by public	$22
Common units held by ETP	17
General Partner interest and incentive distributions held by ETP	1
Total distributions declared	$40

New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity ("ASU 2014-08"), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity's operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December

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31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

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, 2014 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition. Revenues for sales of natural gas and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available.

Our intrastate transportation and storage and interstate transportation 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.

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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. A portion of our gasoline and diesel sales are to wholesale customers on a consignment basis, in which we retain title to inventory, control access to and sale of fuel inventory, and recognize revenue at the time the fuel is sold to the ultimate customer. We typically own the fuel dispensing equipment and underground storage tanks at consignment sites,

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and in some cases we own the entire site and have entered into an operating lease with the wholesale customer operating the site. In addition, our retail outlets derive other income from lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rental and other ancillary product and service offerings. Some of Sunoco, Inc.'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 recorded on a net commission basis and 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 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

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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.

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 Obligations. 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 certain amounts recorded by Panhandle, Sunoco Logistics and our retail marketing operations, discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2014 and 2013, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle'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, Inc. 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, Inc. 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, 2014, there were no legally restricted funds for the purpose of settling AROs.

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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.

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 11 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, 2014, 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

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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 $116 million have been included in ETP's consolidated balance sheet as of December 31, 2014. All of the deferred income tax assets attributable to state and federal NOL benefits expire before 2033 as more fully described below. The state NOL carryforward benefits of $111 million (net of federal benefit) begin to expire in 2014 with a substantial portion expiring between 2029 and 2033. The federal NOLs of $5 million ($1 million in benefits) will expire in 2032 and 2033. Less than $1 million of federal alternative minimum tax credit carryforwards remained at December 31, 2014. We have determined that a valuation allowance totaling $84 million (net of federal income tax effects) is required for the state NOLs at December 31, 2014 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;

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- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- 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.

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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, 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, crude and refined products. Dollar amounts are presented in millions.

	December 31, 2014			December 31, 2013		
	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	(232,500)	$(1)	$—	9,457,500	$3	$5
Basis Swaps IFERC/NYMEX[1]	(13,907,500)	—	—	(487,500)	1	—
Swing Swaps	—	—	—	1,937,500	1	—
Options – Calls	5,000,000	—	—	—	—	—
Power (Megawatt):						
Forwards	288,775	—	1	351,050	1	1
Futures	(156,000)	2	—	(772,476)	—	2
Options – Puts	(72,000)	—	1	(52,800)	—	—
Options – Calls	198,556	—	—	103,200	—	—
Crude (Bbls) – Futures	—	—	—	103,000	—	1
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	57,500	(3)	—	570,000	—	—
Swing Swaps IFERC	46,150,000	2	1	(9,690,000)	1	—
Fixed Swaps/Futures	(8,779,000)	4	2	(8,195,000)	13	3
Forward Physical Contracts	(9,116,777)	—	3	5,668,559	(1)	2
Natural Gas Liquid (Bbls) – Forwards/Swaps	(2,179,400)	13	9	(1,133,600)	—	3
Refined Products (Bbls) – Futures	13,745,755	15	11	(280,000)	—	17
Fair Value Hedging Derivatives (Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(39,287,500)	3	1	(7,352,500)	—	—
Fixed Swaps/Futures	(39,287,500)	48	12	(50,530,000)	(11)	23
Cash Flow Hedging Derivatives (Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	—	—	—	(1,825,000)	—	—
Fixed Swaps/Futures	—	—	—	(12,775,000)	(3)	6
Natural Gas Liquid (Bbls) – Forwards/Swaps	—	—	—	(780,000)	(1)	4
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, 2014, we had $2.04 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $22 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:

Entity	Term	Type[1]	Notional Amount Outstanding December 31, 2014	Notional Amount Outstanding December 31, 2013
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	$—	$400
ETP	July 2015[2]	Forward-starting to pay a fixed rate of 3.38% and receive a floating rate	200	—
ETP	July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	—
ETP	July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	—
ETP	July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	—
ETP	July 2019[4]	Forward-starting to pay a fixed rate of 3.19% and receive a floating rate	300	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	—	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 1.73% and receive a fixed rate of 3.60%	200	400
Panhandle	November 2021	Pay a fixed rate of 3.82% and receive a floating rate	—	275

(1) Floating rates are based on 3-month LIBOR.

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

(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(4) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $214 million as of December 31, 2014. For the $200 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $2 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.

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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, gas and electric utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that 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, 2014.

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 2013 Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

On August 29, 2014, ETP and Susser completed the previously announced merger of an indirect wholly-owned subsidiary of ETP, with and into Susser, with Susser surviving the merger as a subsidiary of ETP (the "Susser Merger"). Management has acknowledged that it is responsible for establishing and maintaining a system of internal controls over financial reporting for Susser. We are in the process of integrating Susser, and we therefore excluded Susser from our December 31, 2014 assessment of the effectiveness of internal control over financial reporting. Susser had total assets of $2.68 billion at December 31, 2014 and third party revenue of $1.62 billion from August 29, 2014 to December 31, 2014 included in our consolidated financial statements as of and for the year ended December 31, 2014. The Susser Merger has not materially affected and is not expected to materially affect our internal control over

financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient controls over the substantive results of our financial reporting throughout this integration process.

Our assessment of internal control over financial reporting did include an assessment of Sunoco LP, which ETP obtained control of in connection with the Susser Merger.

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Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2014, 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, 2014, based on criteria established in the 2013 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. Our audit of, and opinion on, the Partnership's internal control over financial reporting does not include the internal control over financial reporting of Susser Holdings Corporation, a consolidated subsidiary, whose financial statements reflect total assets and revenues constituting 6 and 3 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014. As indicated in Management's Report on Internal Control over Financial Reporting, Susser Holdings Corporation was acquired during 2014. Management's assertion on the effectiveness of the Partnership's internal control over financial reporting excluded internal control over financial reporting of Susser Holdings Corporation. We did not audit the internal control over financial reporting of Sunoco LP, a consolidated subsidiary, whose financial statements as of December 31, 2014 and for the period from September 1, 2014 to December 31, 2014 reflect total assets and revenues constituting 5 and 2 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014. Sunoco LP's internal control over financial reporting was audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to Sunoco LP's internal control over financial reporting in relation to the Partnership taken as a whole, is based solely on the report of the other auditors.

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 and the report of the other auditors provide 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, based on our audit and the report of the other auditors, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in the 2013 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, 2014, and

our report dated March 2, 2015 expressed an unqualified opinion on those financial statements.
/s/ GRANT THORNTON LLP
Dallas, Texas
March 2, 2015

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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, 2014 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, 2014, 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 determined that Messrs. Collins, Glaske, Grimm, and Skidmore all met 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 2014, 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 2014. 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. Michael K. Grimm and David K. Skidmore currently serve on the Audit Committee and Paul E. Glaske served as the chairman of the Audit Committee until he passed away on January 30, 2015.

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 March 2, 2015. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	59	Chief Executive Officer and Chairman of the Board of Directors
Marshall S. (Mackie) McCrea, III	55	President, Chief Operating Officer and Director
Martin Salinas, Jr.	43	Chief Financial Officer
Jamie Welch	48	Director and ETE Group Chief Financial Officer and Head of Business Development
Thomas P. Mason	58	Senior Vice President, General Counsel and Secretary
Richard Cargile	55	President of Midstream Operations
Robert W. Owens	61	President of Retail Marketing
Ted Collins, Jr.	76	Director
Michael K. Grimm	60	Director
James R. (Rick) Perry	64	Director
David K. Skidmore	59	Director

Messrs. Warren, McCrea and Welch also serve as directors of ETE's general partner.

Mr. Paul E. Glaske served as a director until he passed away on January 30, 2015.

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, of Sunoco Logistics and of Sunoco LP. 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 and Sunoco LP.

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

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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.

Robert W. Owens. Mr. Owens is President and Chief Executive Officer of Sunoco LP. and also served as President and Chief Executive Officer of Sunoco, Inc. since 2012 when ETP acquired Sunoco, Inc. Previously he was Senior Vice President of Marketing of Sunoco, Inc., where he was responsible for the retail network; all commercial supply and trading activities involving crude oil, refined products, and petrochemicals; as well as wholesale marketing and transportation operations. Prior to joining Sunoco, Inc. in 1997, Mr. Owens held executive positions at Ultramar Diamond Shamrock Corporation, Amerada Hess Corporation and Mobil Oil Corporation. Mr. Owens holds a B.S. in Business Administration and Marketing from California Polytechnic State University and a M.B.A. from the Kellogg Graduate School of Management at Northwestern University.

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.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. He also serves as a Director of Oasis Petroleum Corp., CLL Global Research Foundation and RSP Permian, Inc. (NYSE: RSP). Mr. Collins is also the Chairman of the Board of Managers of Coronado Midstream, LLC. 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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James R. (Rick) Perry. Mr. Perry has served as a director of our general partner since February 2015. Prior to joining ETP, Mr. Perry served as Governor of the State of Texas from 2000 to 2015. Mr. Perry served as Lieutenant Governor of Texas from 1998 to 2000, and as Agriculture Commissioner from 1994 to 1998. Prior to 1994, Mr. Perry also served in the Texas House of Representatives. The Board selected Mr. Perry to serve as a director because of his vast experience as an executive in the highest office of state government. In addition, Mr. Perry has been involved in finance and budget planning processes throughout his career in government as a member of the Texas House Appropriations Committee, the Legislative Budget Board and as Governor.

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 8 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, 2014, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, except as set forth below:

- late filing of a Form 3 for Energy Transfer Partners, L.P.;
- late filing of a Form 4 for Mr. Glaske;
- late filing of a Form 4 for Mr. Grimm;

- late filing of a Form 4 for Mr. Collins;
- late filing of a Form 4 for Mr. McCrea;
- late filing of a Form 4 for Mr. Salinas; and
- late filing of a Form 4 for Mr. Mason.

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ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner, which in turn is managed by its general partner, ETP LLC, which we refer to in this Item as "our General Partner." As of December 31, 2014, ETE owned 100% of our General Partner, approximately 8.7% 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.

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
- Robert W. Owens, President of Retail Marketing.

During 2014, Mr. Owens' primary business responsibilities were for ETP's retail marking segment, including its Sunoco, Inc. subsidiary and its Sunoco LP affiliate of which the Partnership owns indirectly 100% of the general partner interests. The compensation committee of Sunoco LP's general partner sets the components of Mr. Owens' compensation, including salary, long-term incentive awards and annual bonus utilizing the same philosophy and methodology adopted by our General Partner.

Our General Partner's Philosophy for Compensation of Executives

In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based or "at-risk" compensation and that executives' total compensation levels should be highly 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 (i.e. approximately the 40th percentile of market) 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 time-based 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 generally on continued employment through each specified vesting date. Beginning in December 2012, we began granting restricted unit awards that vest, based generally 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

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executive compensation from our General Partner. For the year ended December 31, 2014, 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;
- 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, 2014, the compensation paid to our named executive officers, other than our Chief Executive Officer, 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 Chief Executive Officer, 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 employee premium contributions 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.

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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. In addition to the information received as a result of a periodic engagement of a third party consultant, the Compensation Committee also utilizes information obtained from other sources, such as annual third party surveys, in its determination of compensation levels for our named executive officers.

Mercer did not provide any additional executive compensation services for the Compensation Committee during 2014. For 2014, the Compensation Committee continued to use the results of the 2013 Mercer compensation analysis, adjusted to account for general inflation and 2014 third party survey results.

Base Salary. Base salary is designed to provide for a competitive fixed level of pay that attracts and retains executive officers, and compensates them for their level of responsibility and sustained individual performance (including experience, scope of responsibility and results achieved). The salaries of the named executive officers are reviewed on an annual basis. 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 (i.e. approximately the 40th percentile of market) and are determined by the Compensation Committee after taking into account the recommendations of Mr. Warren. During the 2014 merit review process, the Compensation Committee approved an increase of 3.0% to Mr. Salinas' annual base salary and held the base salary of Messrs. McCrea and Mason at their existing amounts. The Compensation Committee determined that the increase to Mr. Salinas' base salary was warranted based on the results of the Mercer study and the factors described below under "Annual Bonus." The Compensation Committee also determined that holding the base salaries constant for Messrs. McCrea and Mason was reasonable in light of the Mercer study and the base salary adjustments made in 2013. In the case of Mr. Owens, the compensation committee of the general partner of Sunoco LP, in consultation with the General Partner, increased his base salary to $600,000 or 9.7% from its previous level of $546,763; this increase was approved in November 2014 and became effective in January 2015. Mr. Owens' increase was based principally on his increase of duties as the President of Retail Marketing related to the acquisition by the Partnership of Susser in 2014.

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 previous years, the Compensation Committee has taken into account whether the Partnership achieved or exceeded its targeted performance objectives, which are 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

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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.

In 2014, the board of directors of our General Partner, upon recommendation by the Compensation Committee, approved the Energy Transfer Partners, L.L.C. Annual Bonus Plan (the "New Bonus Plan"), which replaces the ETP Midstream Bonus plan (the "Prior Bonus Plan"). The New Bonus Plan, which became effective for calendar year 2014, is substantially similar to the Prior Bonus Plan, except that the New Bonus plan includes an additional performance criteria related to ETP's internal department financial budget in addition to the previous performance measure of an internal earnings target generally based on targeted EBITDA (the "Earnings Target") budget. Under the New Bonus Plan, the Compensation Committee's evaluation of performance and determination of an overall available bonus pool is based on the Partnership's Earnings Target and the performance of each department compared to the applicable departmental budget (with such performance measured based on the specific dollar amount of general and administrative expenses set for each department). The two performance criteria are weighted 75% on the internal Earnings Target criteria and 25% on internal department financial budget criteria.

In adopting the New Bonus Plan, the board of directors of our General Partner and the Compensation Committee have reaffirmed internal Earnings Target as the primary performance factor in determining annual bonuses. The addition of the internal department financial budget criteria is designed to ensure that the Partnership is effectively managing general and administrative costs in a prudent manner.

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 Earnings Target and at or below internal department financial budgets would support bonuses to our named executive officers ranging from 100% to 125% of their annual bonus target. For 2014, the Compensation Committee retained the same short-term annual cash bonus targets from 2013 for each of the named executive officers. The specific targets are as follows: for Mr. McCrea, 140% of his annual base salary, for Mr. Salinas, 120% of his annual base salary, for Mr. Mason, 125% of his annual base salary and for Mr. Owens, 120% of his annual base salary. In the cases of Messrs. McCrea, Salinas and Mason, their annual bonus targets were increased in 2013 to their current levels from the previous target of 100% of annual base salary consistent with the results of the Mercer study. Mr. Owens' target of 120% was developed and approved by the compensation committee of the general partner of Sunoco LP in consultation with the General Partner. For 2014, Mr. Owens' target was 120% of his annual base salary with the ability to earn up to a maximum of 150% of annual base salary if the retail business segment of the Partnership achieves 120% or more of its Earnings Target.

In respect of 2014 performance, in February 2015, the Compensation Committee approved cash bonuses relating to the 2014 calendar year to Messrs. McCrea, Salinas and Mason of $1,120,000, $546,750 and $687,500, respectively. The compensation committee of the general partner of Sunoco LP approved a cash bonus relating to the 2014 calendar year to Mr. Owens in the amount of $820,145, which award was also approved by the Compensation Committee. 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 2014. The cash bonuses awarded to each of the named executive officers for 2014 were consistent with their respective targets.

Equity Awards. We currently have two incentive plans: (i) the Amended and Restated Energy Transfer Partners, L.P. 2004 Unit Plan (as amended and restated as of June 27, 2007, the "2004 Unit Plan") and (ii) the Second Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan (the "2008 Incentive Plan"). 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 restricted unit award and the vesting structure of those restricted 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 restricted unit award, ETP Common Units are issued. During 2014, Mr. Owens participated in the Sunoco LP 2012 Long-Term Incentive Plan (the “SUN Plan”) under which restricted phantom units are awarded, such restricted phantom units have the same vesting terms as awards received by Messrs. McCrea, Salinas and Mason under the 2008 Incentive Plan.

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For 2014, Mr. McCrea's long-term incentive target increased from 700% of his annual base salary to 750% of his base salary. In the cases of Messrs. Salinas and Mason, their annual long-term incentive targets remained at 300% and 400%, respectively, of their annual base salary. The compensation committee of the general partner of Sunoco LP, in consultation with the General Partner, increased Mr. Owens' annual long-term target from 200% of his annual base salary to 300% of his base salary in consideration of his additional responsibilities as the President of Retail Marketing related to the acquisition by the Partnership of Susser in 2014.

In December 2014, the Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas and Mason of 62,650 units, 14,450 units and 11,500 units, respectively, under the 2008 Incentive Plan related to ETP Common Units. As described below in the section titled "Subsidiary Equity Awards," for 2013, in discussions between the Compensation Committee as well as the compensation committee of the general partners of Sunoco Logistics and Regency, it was determined that portions of total long-term incentive award target values of Messrs. McCrea, Salinas and Mason would be composed of restricted units/restricted phantom units awarded under the equity incentive plans of Sunoco Logistics and/or Regency in consideration for their roles and responsibilities at those partnerships. For Messrs. McCrea and Salinas, their total 2014 long-term incentive awards were allocated 2/3 to the 2008 Incentive Plan and 1/3 to the Sunoco Logistics equity plan. For Mr. Mason, his total 2014 long-term incentive awards were allocated 1/3 to the 2008 Incentive Plan, 1/3 to the Sunoco Logistics equity plan and 1/3 to the Regency equity plan. At Sunoco Logistics, Mr. McCrea serves as Chairman of the Board of Sunoco Logistics' general partner, Mr. Salinas serves as a member of the board and Chief Financial Officer of Sunoco Logistics' general partner, and Mr. Mason serves as a member of the board and legal advisor in matters related to mergers and acquisitions and financing activities. It is expected that the long-term equity awards of the named executive officers of the Partnership will recognize a similar aggregation of awards. The terms and conditions of the restricted unit awards to Messrs. McCrea, Salinas and Mason under the Sunoco Logistics and/or Regency equity incentive plans are identical to the terms and conditions of the restricted unit awards under our equity incentive plan to Messrs. McCrea, Salinas and Mason.

The restricted 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, generally subject to continued employment through each specified vesting date. The restricted unit awards entitle the recipients of the restricted 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 restricted 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 awards subject to vesting. Vesting of the 2014 awards would accelerate in the event of the death or disability of the named executive officer or in the event of a change in control of the Partnership as that term is defined under the 2008 Incentive Plan.

In the case of Mr. Owens, he received two long-term incentive awards under the SUN Plan for 2014. The first award of 50,000 restricted phantom units was awarded by the compensation committee of the general partner of Sunoco LP in consultation with the General Partner in connection with the acquisition of Susser by the Partnership in 2014 and the additional responsibilities to be undertaken by Mr. Owens as the President and Chief Executive Officer of Sunoco, Inc. and the general partner of Sunoco LP. In addition, in January 2015, the compensation committee of the general partner of Sunoco LP finalized and approved, in consultation with the General Partner, 2014 long-term incentive awards to legacy Sunoco, Inc. personnel under the SUN Plan. Mr. Owens was awarded 39,160 restricted phantom units. Both the award of 50,000 restricted phantom units in November 2014 and the award of 39,160 restricted phantom units in January 2015 were awarded on identical terms and conditions with respect to vesting and the right to DER payments, as those awarded to Messrs. McCrea, Salinas and Mason under the 2008 Incentive Plan in 2014.

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 restricted 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. In addition, in the event of a change in control of the Partnership, all unvested awards granted under the 2004 Unit Plan, as well as awards granted in 2014 under the 2008 Incentive Plan, would be accelerated. For awards previously granted under the 2008 Incentive Plan prior to December 2014, unvested awards may also become vested upon a change in control at the discretion of the Compensation Committee.

The Compensation Committee has in the past and may in the future, but is not required to, accelerate the vesting of unvested restricted unit awards in the event of the termination or retirement of an executive officer. The Compensation Committee did not accelerate the vesting of restricted unit awards to any named executive officers in 2014.

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As discussed below under “Potential Payments Upon a Termination or Change of Control,” certain equity awards automatically accelerate upon a change in control event, which means vesting automatically accelerates upon a change of control irrespective of whether the officer is terminated. In addition, the 2014 awards to Mr. McCrea and the January 2015 award to Mr. Owens included a provision in the applicable award agreement for acceleration of unvested restricted unit/restricted phantom unit awards upon a termination of employment by the general partner of the applicable partnership issuing the award without “cause”. For purposes of the awards the term “cause” shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates by, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliate. We believe that permitting the accelerated vesting of equity awards upon a change in control creates an important retention tool for us by enabling employees to realize value from these awards in the event that we undergo a change in control transaction. In addition, we believe permitting acceleration of vesting upon a change in control and the acceleration of vesting awards upon a termination without “cause” in the case of the 2014 unit awards to Mr. McCrea and the January 2015 unit awards to Mr. Owens creates a sense of stability in the course of transactions that could create uncertainty regarding their future employment and encourage these officers to remain focused on their job responsibilities.

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 Messrs. McCrea, Mason and Salinas beginning December 2015 and Mr. Owens beginning in December 2018.

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.

Affiliate and Subsidiary Equity Awards. In addition to their roles as officers of our General Partner, Messrs. McCrea and Salinas serve as officers and directors of the general partner of Sunoco Logistics, Mr. Mason serves as a director of the general partner of Sunoco Logistics and provides certain legal services to the general partners of Sunoco Logistics and Regency. In connection with those roles at Sunoco Logistics and Regency, in December 2014, the compensation committee of Sunoco Logistics' general partner awarded Messrs. McCrea, Salinas and Mason time-based restricted units of Sunoco Logistics in the amount of 41,136 units, 9,502

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units and 15,117 units, respectively, and the compensation committee of Regency's general partner awarded Mr. Mason 24,500 restricted phantom units. The terms and conditions of the restricted unit awards to Messrs. McCrea, Salinas and Mason under the Sunoco Logistics and/or Regency equity plans are identical to the terms and conditions of the restricted unit awards under our equity plan to Messrs. McCrea, Salinas and Mason, including the provisions related to acceleration for termination without "cause" for Mr. McCrea.

Qualified Retirement Plan Benefits.

The Energy Transfer Partners GP, L.P. 401(k) Plan (the "ETP 401(k) Plan") is a defined contribution 401(k) plan, which covers substantially all of our employees, including the 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 are fully vested at all times, and the amounts contributed by the Partnership become vested based on years of service. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement. From January 1, 2014 through June 30, 2014, the general partner previously made a discretionary profit sharing contribution of 7% of base pay on behalf of Mr. Owens, subject to IRS contribution limits. This profit sharing contribution was previously included in the Sunoco sponsored 401(k) which was merged with the ETP 401(k) Plan effective January 1, 2014. 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.

The Sunoco, Inc. Retirement Plan (the "SCIRP") is a qualified defined benefit plan sponsored by Sunoco, Inc., under which benefits are subject to IRS limits for pay and amount. None of our named executive officers other than Mr. Owens has ever participated or been eligible to participate in SCIRP.

Under the SCIRP, the benefit for executives hired before January 1, 1987 is calculated based upon the greater of a "final average pay" formula or a "cash balance" formula, the former providing a benefit using a formula that includes final average earnings and eligible service and the latter providing a benefit based upon a percentage of earnings. Those executives hired on or after January 1, 1987 (including Mr. Owens) participate in the cash balance formula. Effective June 30, 2010, Sunoco, Inc. froze pension benefits (including accrued and vested benefits) payable under this plan for all salaried employees, including Mr. Owens, who participate in this plan. On October 31, 2014, Sunoco, Inc. terminated the SCIRP. Distributions of benefits from the SCIRP will be made following approval from the IRS and Pension Benefit Guaranty Corporation ("PBGC") for such termination.

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 restricted 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 restricted unit awards in the event of a change of control, as defined in the plan. In the case of the December 2014 long-term incentive awards to the named executive officers under the 2008 Incentive Plan, the SUN Plan or as applicable the equity incentive plans of Sunoco Logistics and Regency, the awards would immediately and fully vest all unvested restricted unit awards in the event of a change in control, as defined in the plan. In addition, the December 2014 award to Mr. McCrea under the 2008 Incentive Plan and the January 2015 award to Mr. Owens under the SUN Plan provide for acceleration in the event of termination without cause. 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-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.

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ETP 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.

ETP Deferred Compensation Plan for Former Sunoco Executives. We maintain a deferred compensation plan established by ETP in connection with the merger with Sunoco (the "Sunoco Executive DC Plan"). Pursuant to his offer letter from ETP, in connection with the Sunoco Merger, Mr. Owens waived any future rights or benefits to which he otherwise would have been entitled under both the Sunoco, Inc. Executive Retirement Plan and the Sunoco Inc. Pension Restoration Plan, non-qualified, unfunded plans that provided supplemental pension benefits over and above the benefits provided under the SCIRP, in return for which, the present value $6,655,750 of such deferred compensation benefits was credited to Mr. Owens' account under the Sunoco Executive DC Plan. Mr. Owens is our only named executive officer eligible to participate in the Sunoco Executive DC Plan. Mr. Owens' account is 100% vested and will be distributed in one lump sum payment upon his retirement or termination of employment or other designated distribution event, including a change of control as defined in the plan. Mr. Owens' account is credited with deemed earnings or losses based on hypothetical investment fund choices made by him among available funds.

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 U.S. 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 9 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm and Skidmore are the only members of the Compensation Committee. During 2014, no member of the Compensation Committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with

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respect to which any of our executive officers served on such company's board of directors. In addition, neither Mr. Grimm nor Mr. Skidmore is a former employee of ours or any of our subsidiaries.

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 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]	2014	$6,921	$—	$—	$—	$ —	$ —	$ —	$6,921
Chief Executive	2013	5,814	—	—	—	—	—	—	5,814
Officer	2012	3,700	—	—	—	—	—	—	3,700
Martin Salinas, Jr.	2014	455,625	546,750	1,345,143	—	—	15,468	21,795	2,384,781
Chief Financial	2013	437,019	524,423	1,861,698	—	—	56,036	26,136	2,905,312
Officer	2012	392,750	375,000	755,515	—	—	23,261	26,140	1,572,666
Marshall S. (Mackie) McCrea, III	2014	800,000	1,120,000	5,829,111	—	—	—	14,072	7,763,183
President and Chief	2013	772,115	1,080,961	6,715,336	—	—	—	13,323	8,581,735
Operating Officer	2012	690,000	700,000	1,510,985	—	—	—	12,802	2,913,787
Thomas P. Mason	2014	550,000	687,500	2,009,668	—	—	—	37,576	3,284,744
Senior Vice	2013	517,308	646,635	2,308,057	—	—	—	36,923	3,508,923
President, General Counsel and Secretary	2012	466,424	500,000	1,359,900	—	—	—	35,998	2,362,322
Robert W. Owens	2014	546,763	820,145	2,275,000	—	—	1,547,619	32,465	5,221,992
President of Retail Marketing									

(1) The discretionary cash bonus amounts for our named executive officers for 2014 reflect cash bonuses approved by the Compensation Committee in February 2015 that are expected to be paid in March 2015.

(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. For Messrs. Salinas, McCrea and Mason, amounts include equity awards of our subsidiaries and affiliates, as reflected in the “Grants of Plan-Based Awards Table.” See Note 9 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2014 in this column include (i) matching contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $4,635 for Mr. Salinas, $7,784 for Mr. Owens and $13,000 each for Messrs. McCrea and Mason, (ii) profit-sharing contributions of $19,137 made to a Sunoco, Inc. savings plan on behalf of Mr. Owens (iii) expenses paid by us for housing for Messrs. Salinas and Mason near our executive office in Dallas and (iv) 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.	12/16/2014	14,450	—	—	888,097
Marshall S. (Mackie) McCrea, III	12/16/2014	62,650	—	—	3,850,469
Thomas P. Mason	12/16/2014	11,500	—	—	706,790
Sunoco Logistics Unit Awards:					
Martin Salinas, Jr.	12/5/2014	9,502	—	—	457,046
Marshall S. (Mackie) McCrea, III	12/5/2014	41,136	—	—	1,978,642
Thomas P. Mason	12/5/2014	15,117	—	—	727,128
Regency Unit Awards:					
Thomas P. Mason	12/19/2014	24,500	—	—	575,750
Sunoco LP Unit Awards:					
Robert W. Owens	11/10/2014	50,000			2,275,000

(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 9 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

		Unit Awards	
Name	Grant Date[1]	Equity Incentive Plan Awards: Number of Units That Have Not Vested[1][2] (#)	Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested[3] ($)
ETP Unit Awards:			
Kelcy L. Warren	N/A	—	$—
Martin Salinas, Jr.	12/16/2014	14,450	939,250
	12/30/2013	16,724	1,087,060
	1/10/2013	16,667	1,083,355
	12/20/2011	10,000	650,000
	12/15/2010	4,000	260,000
Marshall S. (Mackie) McCrea, III	12/16/2014	62,650	4,072,250
	12/30/2013	69,375	4,509,375
	1/10/2013	33,333	2,166,645
	12/20/2011	20,000	1,300,000
	5/2/2011	27,200	1,768,000
	1/14/2011	50,000	3,250,000
Thomas P. Mason	12/16/2014	11,500	747,500
	12/30/2013	40,923	2,659,995
	1/10/2013	30,000	1,950,000
	12/20/2011	16,000	1,040,000
	12/15/2010	4,000	260,000
Robert W. Owens	12/30/2013	20,000	1,300,000
	12/5/2012	36,000	2,340,000
Sunoco Logistics Unit Awards:			
Martin Salinas, Jr.	12/5/2014	9,502	396,994
	12/5/2013	13,100	547,318
	1/24/2013	9,998	417,716
Marshall S. (Mackie) McCrea, III	12/5/2014	41,136	1,718,662
	12/5/2013	54,600	2,281,188
	1/24/2013	19,998	835,516
Thomas P. Mason	12/5/2014	15,117	631,588
Regency Unit Awards:			
Thomas P. Mason	12/19/2014	24,500	588,000
Sunoco LP Unit Awards:			
Robert W. Owens	11/10/2014	50,000	2,488,500

(1) ETP and Sunoco LP common unit awards outstanding to Messrs. Salinas, McCrea, Mason and Owens vest as follows:

- at a rate of 60% in December 2017 and 40% in December 2019 for ETP awards granted in December 2014 and Sunoco LP awards granted in November 2014;
- 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 2017 for awards granted in December 2012;

- ratably in December of each year through 2016 for awards granted in December 2011 and March 2012; and
- ratably in December of each year through 2015 for awards granted in December 2010, January 2011 and May 2011.

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

- at a rate of 60% in December 2017 and 40% in December 2019 for awards granted in December 2014;
- at a rate of 60% in December 2016 and 40% in December 2018 for awards granted in December 2013; and
- ratably in December of each year through 2017 for awards granted in January 2013.

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Regency common unit awards outstanding to Mr. Mason vest as follows:

- at a rate of 60% in December 2017 and 40% in December 2019 for awards granted in December 2014.

(2) Sunoco Logistics unit amounts reflect the two-for-one split of Sunoco Logistics common units in June 2014.

(3) Market value was computed as the number of unvested awards as of December 31, 2014 multiplied by the closing price of our Common Units, Sunoco Logistics common units, or Regency common units, accordingly, on December 31, 2014.

Option Exercises and Units Vested Table

Name	Unit Awards	
	Number of Units Acquired on Vesting[1][2] (#)	Value Realized on Vesting[1] ($)
ETP Unit Awards:		
Kelcy L. Warren	—	$—
Martin Salinas, Jr.	12,837	845,599
Marshall S. (Mackie) McCrea, III	91,200	6,007,526
Thomas P. Mason	15,637	1,030,040
Robert W. Owens	24,000	1,580,928
Sunoco Logistics Unit Awards:		
Martin Salinas, Jr.	3,334	160,165
Marshall S. (Mackie) McCrea, III	6,668	320,331

(1) Amounts presented represent the number of unit awards vested during 2014 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.

(2) Sunoco Logistics unit amounts reflect the two-for-one split of Sunoco Logistics common units in June 2014.

We have not issued option awards.

Pension Benefits Table

The following table shows the actuarial present value of Mr. Owens' retirement benefit under the SCIRP through December 31, 2014, together with years of credited service. The table below shows Mr. Owens' estimated retirement benefit payable based under the cash balance formula of SCIRP. Mr. Owens may elect to receive his accrued SCIRP benefits in the form of either a lump sum or an annuity option upon retirement/termination. The estimates shown in the table below assume that benefits are received in the form of a single lump sum at retirement. Effective June 30, 2010, Sunoco, Inc. froze pension benefits for all salaried and many non-union employees. This freeze also applies to Mr. Owens. On October 31, 2014, Sunoco, Inc. terminated the SCIRP. Distributions of benefits from the SCIRP will be made following approval from the IRS and PBGC for such termination.

Name	Number of Years of Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
Robert W. Owens	13.45	$506,739	$—

Mr. Owens retirement benefit is calculated using SCIRP's Career Pay (cash balance) formula and is expressed as an account balance, comprised of pay credits and indexing adjustments.

Pay credits equal 7% of pay for the year up to the Social Security (FICA) Wage Base ($117,000 in 2014) plus 12% of pay that exceeds the Wage Base for the year. The indexing adjustment equals the account balance at the end of each month multiplied by the monthly change in the All-Urban Consumer Price Index, plus 0.17%. However, if in any month the adjustment would be negative, the adjustment would be zero for such month. Beginning November 1, 2014, the indexing adjustment is fixed at 4.22% annually.

Mr. Owens may retire at the SCIRP's normal retirement age of 65, or may retire now as he has satisfied the SCIRP's early retirement requirements (i.e., age 55 with 10 years of service).

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Nonqualified Deferred Compensation

The following table provides the voluntary salary deferrals made by the named executive officers in 2014 under the DC Plan and, in the case of Mr. Owens, the Sunoco Executive DC Plan.

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE ($)
Kelcy L. Warren	$—	$—	$—	$ —	$—
Martin Salinas, Jr.	104,575	—	15,468	—	423,538
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Robert W. Owens	164,160	—	1,499,620	373,052	8,144,037

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, the restricted unit awards under the 2004 Unit Plan, the 2008 Incentive Plan as well as the equity incentive plans of Regency and Sunoco Logistics, generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of the death or disability of the award recipient prior to the applicable vesting period being satisfied. In addition, in the event of a change in control of the partnership, all unvested awards granted under the 2004 Unit Plan, as well as awards granted in 2014 under the 2008 Incentive Plan, the SUN Plan and/or the equity incentive plans of Regency and Sunoco Logistics would be accelerated. For awards granted under the 2008 Incentive Plan prior to December 2014, unvested awards may also become vested upon a change in control at the discretion of the applicable compensation committee. This discussion assumes a scenario in which the ETP Compensation Committee did not exercise their discretion to accelerate unvested awards in connection with a change in control.

The 2014 awards to Mr. McCrea awarded under the 2008 Incentive Plan and the equity incentive plan of Sunoco Logistics included a provision in the applicable award agreement for acceleration of unvested restricted unit/restricted phantom unit awards upon a termination of employment by the general partner of the applicable partnership issuing the award without "cause". For purposes of the awards the term "cause" shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates by, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliate.

In addition, the awards under the 2004 Plan, 2008 Incentive Plan, the SUN Plan, the equity incentive plan of Regency and the 2014 awards under the Sunoco Logistics equity incentive plan all provide for acceleration of vesting in the event of the death or disability of the award recipient.

In the event of death, the named executive officers participate in the life insurance plans offered to all of our employees (i.e., life insurance benefits equal to one and one-half times the named executive officer's annual base salary, up to a maximum of $750,000 plus any supplemental life insurance elected and paid for by the named executive officer).

Pension Benefits. In the event of a change of control, under SCIRP, a participant's service is increased by three years, subject to reduction for service after the change in control. In the month of termination, a participant's Career Pay Earnings are increased by an amount equal to 36 months less the number of months worked after the Change in

Control, times the greater of Career Pay Earnings for: (A) the month preceding termination or (B) the month preceding the change in control. For purposes of (A) and (B) monthly earnings will include base pay and 1/12 of the annual bonus target.

As of December 31, 2014, the increase in the present value of Mr. Owens' accumulated pension benefits upon a change in control would be $486,237.

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Deferred Compensation Plan. As discussed in our Compensation Discussion and Analysis above, all amounts under the DC Plan and the Sunoco Executive DC Plan (other than discretionary credits) are 100% vested. Upon a change in control (as defined in the DC Plan and/or the Sunoco Executive DC Plan), distributions from the DC Plan and/or the Sunoco Executive DC Plan would be made in accordance with the normal distribution provisions. A change in control is generally defined in the DC Plan and the Sunoco Executive 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 2014, non-employee directors each 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 2014, 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 2014, Mr. Glaske received additional compensation of $10,000, Mr. Collins received additional compensation of $15,000 and Messrs. Grimm and Skidmore each received additional compensation of $25,000. 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, non-employee directors received 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 2014 is reflected in the following table:

Name	Fees Paid in Cash[1] ($)	Unit Awards[2] ($)	All Other Compensation ($)	Total ($)
Paul E. Glaske	$84,600	$100,000	$—	$184,600
Ted Collins, Jr.	65,000	100,000	—	165,000
Michael K. Grimm	114,100	100,000	—	214,100
David K. Skidmore	111,600	100,000	—	211,600

(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.

As of December 31, 2014, Messrs. Glaske, Collins and Grimm each had 4,774 unit awards outstanding and Mr. Skidmore had 5,818 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, 2014:

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	3,528,621	$—	5,377,734
Equity compensation plans not approved by security holders	—	—	—
Total	3,528,621	—	5,377,734

Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 18, 2015, 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	21,177	*	
	Marshall S. (Mackie) McCrea , III	283,154	*	
	Martin Salinas, Jr.	53,325	*	
	Jamie Welch	20,000	*	
	Thomas P. Mason	97,629	*	
	Richard Cargile	12,887	*	
	Robert W. Owens	—	*	
	Ted Collins, Jr.	100,512	*	
	Michael K. Grimm	23,650	*	
	James R. (Rick) Perry	—	*	
	David K. Skidmore	3,020	*	
	All Directors and Executive Officers as a Group (11 Persons)	615,354	*	
	ETE[4]	25,614,102	7.2	%
	ETE Holdings[4]	5,226,967	1.5	%
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, Collins, Grimm, Perry 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 Mr. Owens and 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, 30.8 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 14 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 $26 million, $27 million and $18 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, 2014, 2013 and 2012, respectively.

Immediately following the closing of the Partnership's acquisition of Sunoco, Inc., ETE contributed its interest in Southern Union into ETP Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in ETP Holdco. In conjunction with ETE's contribution, the Partnership contributed its interest in Sunoco, Inc. to ETP Holdco and retained a 40% equity interest in ETP Holdco. Prior to the contribution of Sunoco, Inc. to ETP Holdco, Sunoco, Inc. 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

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Partnership. The Class F Units were entitled to 35% of the quarterly cash distribution generated by the Partnership and its subsidiaries other than ETP 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 ETP 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 "ETP Holdco Acquisition"). As a result, ETP now owns 100% of ETP 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 ETP 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 and (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.

In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, ETP will also issue 100 Class I Units. In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016. This transaction is expected to close in March 2015.

On February 19, 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, 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 Lake Charles LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles 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, as discussed further in Note 8 to our

consolidated financial statements.

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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,	
	2014	2013
Audit fees[1]	$5,707,500	$6,159,000
Audit related fees[2]	340,893	682,300
Tax fees[3]	79,000	—
Total	$6,127,393	$6,841,300

(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 2014 and 2013 for financial statement audits and interim reviews of subsidiary entities in connection with contribution and sale transactions. Includes fees in 2013 for audits of Sunoco, Inc.'s benefit plans. Includes fees in 2014 and 2013 in connection with the service organization control report on Panhandle'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)	March 2, 2015
/s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer (Principal Financial and Accounting Officer)	March 2, 2015
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	President, Chief Operating Officer and Director	March 2, 2015
/s/ Jamie Welch Jamie Welch	Director	March 2, 2015
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	March 2, 2015
/s/ Michael K. Grimm Michael K. Grimm	Director	March 2, 2015
/s/ James R. Perry James R. Perry	Director	March 2, 2015
/s/ David K. Skidmore David K. Skidmore	Director	March 2, 2015

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INDEX TO EXHIBITS

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

Exhibit Number	Description
2.1	Purchase Agreement, dated March 22, 2011, among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC and Louis Dreyfus Highbridge Energy LLC, Energy Transfer Partners, L.P. and Regency Energy Partners LP. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K/A filed on March 25, 2011)
2.2	Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed October 18, 2011)
2.3	Amendment No. 1, dated December 1, 2011, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed December 7, 2011)
2.4	Amendment No. 2, dated January 11, 2012, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 10.1 to Exhibit 2.1 to Registrant's Form 8-K filed on January 13, 2012)
2.5	Amendment No. 2, dated as of March 23, 2012, to the Amended and Restated Agreement and Plan of Merger, by and among Energy Transfer Partners, L.P., Citrus ETP Acquisition L.L.C., Energy Transfer Equity, L.P., Southern Union Company, and CrossCountry Energy, LLC dated July 19, 2011 (incorporated by reference to Exhibit 3.1 to Registrant's Form 8-K filed on March 28, 2012)
2.6	Amendment No. 1, dated as of September 14, 2011, to the Amended and Restated Agreement and Plan of Merger, dated as of July19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed September 15, 2011)
2.7	Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P., Citrus ETP Acquisition, L.L.C., Energy Transfer Equity, L.P. Southern Union Company and CrossCountry Energy, LLC (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed July 20, 2011)
2.8	Agreement and Plan of Merger, dated as of April 29, 2012 by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc. and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on May 1, 2012)
2.9	Amendment No. 1, dated as of June 15, 2012, to the Agreement and Plan of Merger, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc., and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (Incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on June 20, 2012)
2.10	Transaction Agreement, dated as of June 15, 2012, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage Holdings, Inc., Energy Transfer Equity, L.P., ETE Sigma Holdco, LLC and ETE Holdco Corporation (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on June 20, 2012)
2.11	Agreement and Plan of Merger, dated as of April 27, 2014 by and among Energy Transfer Partners, L.P., Drive Acquisition Corporation, Heritage Holdings, Inc., Energy Transfer Partners GP, L.P., Susser Holdings Corporation, and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on April 28,

	2014)
2.12	Agreement and Plan of Merger, dated as of January 25, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Regency Energy Partners LP, Regency GP LP and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on January 26, 2015)
2.13	Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Rendezvous I LLC, Rendezvous II LLC, Regency Energy Partners LP, Regency GP LP, ETE GP Acquirer LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on February 19, 2015)
3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009 (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed July 29, 2009)

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Exhibit Number	Description
3.1.1	Amendment No. 1, dated March 26, 2012, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 28, 2009 (incorporated by reference to Exhibit 3.1 to Registrant's Form 8-K filed on March 28, 2012)
3.1.2	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated October 5, 2012 (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed October 5, 2012)
3.1.3	Amendment No. 3, dated April 15, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K/A filed on April 18, 2013)
3.1.4	Amendment No. 4, dated April 30, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on May 1, 2013)
3.1.5	Amendment No. 5, dated October 31, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on November 1, 2013)
3.1.6	Amendment No. 6, dated February 19, 2014, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on February 19, 2014)
3.1.7	Amendment No. 7, dated March 3, 2014, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 28, 2009 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on March 5, 2014)
3.1.8	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated August 29, 2014 (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on August 29, 2014)
3.2	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 3.3 to the Registrant's Form 10-Q for the quarter ended February 29, 2004)
3.3	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.5 to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
3.3.1	Amendment No. 2, dated March 26, 2012, to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated as of April 17, 2007 (incorporated by reference to Exhibit 3.2 to Registrant's Form 8-K filed on March 28, 2012)
3.4	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed August 10, 2010)
3.4.1	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated as of August 10, 2010 (incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on March 28, 2012)
3.5	Certificate of Limited Partnership of Sunoco Logistics Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1, File No. 333-71968, filed October 22, 2001)
3.6	Certificate of Limited Partnership of Sunoco Logistics Operations L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 1 to Form S-1, File No. 333-71968, filed December 18, 2001)
3.7	First Amended and Restated Agreement of Limited Partnership of Sunoco Logistics Partners Operations L.P., dated as of February 8, 2002 (incorporated by reference to Exhibit 3.5 of Form 10-K, File No. 1-31219, filed April 1, 2002)
3.8	Third Amended and Restated Agreement of Limited Partnership of Sunoco Logistics Partners L.P., dated as of January 26, 2010 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-31219, filed January 28, 2010)

3.8.1	Amendment No. 1 to Third Amended and Restated Partnership Agreement of Sunoco Logistics Partners L.P., dated as of July 1, 2011 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-31219, filed July 5, 2011)
3.8.2	Amendment No. 2 to Third Amended and Restated Partnership Agreement of Sunoco Logistics Partners L.P., dated as of November 21, 2011 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-31219, filed November 28, 2011)
3.9	Third Amended and Restated Limited Liability Company Agreement of Sunoco Partners LLC dated as of July 1, 2011 (incorporated by reference to Exhibit 3.2 of Form 8-K, File No. 1-31219, filed July 5, 2011)
3.10	Certificate of Formation of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13 to the Registrant’s Form 10-Q for the quarter ended March 31, 2010)

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Exhibit Number	Description
3.10.1	Certificate of Amendment of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
3.11	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.14 to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
4.1	Registration Rights Agreement, dated April 30, 2013, by and between Southern Union Company and Regency Energy Partners LP (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed on May 1, 2013)
4.2	Registration Rights Agreement, dated April 30, 2013, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on May 1, 2013)
4.3	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 3, 2006)
4.4	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005)
4.5	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on January 19, 2005)
4.6	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (Incorporated by reference to Exhibit 10.45 to the Registrant's Form 10-Q for the quarter ended February 28, 2005)
4.7	Form of Senior Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.11 to the Registrant's Form S-3 filed August 9, 2006)
4.8	Form of Subordinated Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.12to the Registrant's Form S-3 filed August 9, 2006)
4.9	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.13 to the Registrant's Form 10-K for the year ended August 31, 2006)
4.10	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 25, 2006)
4.11	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed March 31, 2008)
4.12	Seventh Supplemental Indenture dated December 23, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed December 23, 2008)
4.12.1	Eighth Supplemental Indenture dated April 7, 2009, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on April 7, 2009)

4.13	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed May 12, 2011)
4.14	Tenth Supplemental Indenture, dated as of January 17, 2012, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 1.1 to the Registrant's Form 8-K filed January 17, 2012)
4.15	Eleventh Supplemental Indenture dated as of January 22, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 22, 2013)
4.16	Twelfth Supplemental Indenture dated as of January 24, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed June 26, 2013)

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Exhibit Number	Description
4.17	Thirteenth Supplemental Indenture dated as of September 19, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed September 19, 2013)
4.18	Indenture, dated as of March 31 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 5, 2012)
4.19	First Supplemental Indenture, dated as of March 31, 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee, to the Indenture, dated as of March 31, 2009, relating to Sunoco, Inc.'s 9.625% Senior Notes due 2015 (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed October 5, 2012)
4.20	Second Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as trustee, to Indenture, dated as of March 31, 2009 (incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed October 5, 2012)
4.21	Indenture, dated as of June 30, 2000, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A. (incorporated by reference to Exhibit 4.4 to the Registrant's Form 8-K filed October 5, 2012)
4.22	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of June 30, 2000 (incorporated by reference to Exhibit 4.7 to the Registrant's Form 8-K filed October 5, 2012)
4.23	Indenture, dated as of May 15, 1994, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., relating to Sunoco, Inc.'s 9.00% Debentures due 2024 (incorporated by reference to Exhibit 4.8 to the Registrant's Form 8-K filed October 5, 2012)
4.24	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of May 15, 1994 (incorporated by reference to Exhibit 4.9 to the Registrant's Form 8-K filed October 5, 2012)
+ 10.1*	Second Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit A to the Registrant's Definitive Proxy Statement on Schedule 14A filed October 24, 2014)
+ 10.2	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan (incorporated by reference to Exhibit 10.6.6 to the Registrant's Form 10-Q for the quarter ended June 30, 2008)
+ 10.3	Energy Transfer Partners Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
+ 10.4	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the 2008 Energy Transfer Partners, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 1, 2004)
+ 10.5	Energy Transfer Partners, L.L.C. Annual Bonus Plan effective January 1, 2014 (incorporated by reference to Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended June 30, 2014)
10.6	First Amendment, dated April 30, 2013, to the Services Agreement, effective as of May 26, 2010, by and among Energy Transfer Equity, L.P., ETE Services Company LLC and Regency Energy Partners LP (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
10.7	Second Amendment , dated April 30, 2013, to the Operation and Service Agreement, dated May 19, 2011, as amended, by and among La Grange Acquisition, L.P. d/b/a Energy Transfer Company, Regency Energy Partners LP, Regency GP LP and Regency Gas Services LP (incorporated by reference to Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)

10.8	Guarantee of Collection, dated as of April 30, 2013, by and between Regency Energy Partners LP, PEPL Holdings, LLC and Regency Energy Finance Corp. (incorporated by reference to Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
10.9	Second Amendment, dated April 30, 2013, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010, by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.4 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
10.10	Third Amendment, dated February 19, 2014, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010 and April 30, 2013 by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed on February 19, 2014)
10.11	Support Agreement, dated as of April 27, 2014, by and among Energy Transfer Partners, L.P., Drive Acquisition Corporation, Sam L. Susser and Susser Family Limited Partnership (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed on April 28, 2014)

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Exhibit Number	Description
10.12	Exchange and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and ETE Common Holdings, LLC dated August 7, 2013 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended September 30, 2013)
10.13	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers, and La Grange Acquisition, L.P., as Buyer (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed February 1, 2005)
10.14	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005)
10.15	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 18, 2006)
10.16	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed September 18, 2006)
10.17	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed September 18, 2006)
10.18	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
10.18.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
10.19	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
10.19.1	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 14, 2009)
10.20	Guarantee, dated as of March 22, 2011, by Energy Transfer Partners, L.P. in favor of Louis Dreyfus Highbridge Energy LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K/A filed on March 25, 2011)
10.21	Amended and Restated Limited Liability Company Agreement of ETP-Regency Midstream Holdings, LLC, dated May 2, 2011 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 2, 2011)
10.22	Term Loan Agreement dated as of July 28, 2011, by and among Fayetteville Express Pipeline LLC, The Royal Bank of Scotland plc, as administrative agent, and certain other agents and lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed August 2, 2011)
10.23	Amendment No. 1, dated as of September 14, 2011, to Second Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and Southern Union Company (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 15, 2011)

10.24	Second Amended and Restated Credit Agreement dated as of October 27, 2011 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and an LC Issuer, the other lenders party thereto and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc., as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 2, 2011)
10.25	First Amendment, dated as of November 19, 2013, to Second Amended and Restated Credit Agreement, dated October 27, 2011 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and an LC Issuer, the other lenders party thereto and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc., as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 20, 2013)
10.26	Guarantee of Collection made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on March 28, 2012)
10.27	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC (incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on March 28, 2012)

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Exhibit Number	Description
10.28	Capital Stock Agreement dated June 30, 1986, as amended April 3, 2000 ("Agreement"), among El Paso Energy Corporation (as successor in interest to Sonat, Inc.); CrossCountry Energy, LLC (assignee of Enron Corp., which is the successor in interest to InterNorth, Inc. by virtue of a name change and successor in interest to Houston Natural Gas Corporation by virtue of a merger) and Citrus Corp. (incorporated by reference to Exhibit 10(t) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006)
10.29	Certificate of Incorporation of Citrus Corp. (incorporated by reference to Exhibit 10(q) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006)
10.30	By-Laws of Citrus Corp. (incorporated by reference to Exhibit 10(r) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006)
10.31	Contingent Residual Support Agreement by and among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P. and, for certain limited purposes, UGI Corporation, dated January 12, 2012 (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on January 13, 2012)
10.32	Unitholder Agreement by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated January 12, 2012 (incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on January 13, 2012)
10.33	Letter agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P, dated January 11, 2012 (incorporated by reference to Exhibit 10.3 to Registrant's Form 8-K filed on January 13, 2012)
10.34	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on May 1, 2012)
10.35	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Missouri Acquisition, Inc. and for certain limited purposes The Laclede Group, Inc. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed December 17, 2012)
10.36	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Massachusetts Acquisition, Inc. and for certain limited purposes, The Laclede Group, Inc. (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K filed on December 17, 2012)
10.37	Commitment Increase Agreement by and among Energy Transfer Partners, L.P., the lenders party thereto and Wells Fargo Bank, National Association, in its capacity as administrative agent for the lenders dated as of February 10, 2015 (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed February 17, 2015)
12.1*	Computation of Ratio of Earnings to Fixed Charges.
21.1*	List of Subsidiaries.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ernst & Young LLP related to Sunoco Logistics Partners L.P.
23.3*	Consent of Ernst & Young LLP related to Susser Holdings Corporation.
23.4*	Consent of Ernst & Young LLP related to Sunoco LP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	

	Report of Independent Registered Public Accounting Firm – Ernst & Young LLP opinion on consolidated financial statements of Sunoco Logistics Partners L.P.
99.2*	Report of Independent Registered Public Accounting Firm – Ernst & Young LLP opinion on consolidated financial statements of Susser Holdings Corporation.
99.3*	Report of Independent Registered Public Accounting Firm – Ernst & Young LLP opinion on consolidated financial statements of Sunoco LP.
99.4	Statement of Policies Relating to Potential Conflicts among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and Regency Energy Partners LP dated as of April 26, 2011 (incorporated by reference to Exhibit 99.1 to the Registrant's Form 10-Q filed on August 8, 2011)

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Exhibit Number	Description
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2014 and December 31, 2013; (ii) our Consolidated Statements of Operations for the years ended December 31, 2014, 2013 and 2012; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2014, 2013 and 2012; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2014, 2013 and 2012; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.

** Furnished herewith.

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Sunoco LP and Susser Holdings Corporation, both consolidated subsidiaries, as of December 31, 2014 and for the period from September 1, 2014 to December 31, 2014, whose combined statements reflect total assets constituting 11 percent of consolidated total assets as of December 31, 2014, and total revenues of 5 percent of consolidated total revenues for the year then ended. Those statements were audited by other auditors, whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Sunoco LP and Susser Holdings Corporation, is based solely on the reports of the other auditors. We did not audit the financial statements of Sunoco Logistics Partners L.P., a consolidated subsidiary, for the period from October 5, 2012 to December 31, 2012, which statements reflect revenues of 20 percent of consolidated total revenues for the year ended December 31, 2012. Those statements were audited by other auditors, whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Sunoco Logistics Partners L.P. for the period from October 5, 2012 to December 31, 2012, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Partners, L.P. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2014, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2015 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas

March 2, 2015

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$639	$549
Accounts receivable, net	2,879	3,359
Accounts receivable from related companies	210	165
Inventories	1,389	1,765
Exchanges receivable	44	56
Price risk management assets	7	35
Other current assets	271	310
Total current assets	5,439	6,239
PROPERTY, PLANT AND EQUIPMENT	33,200	28,430
ACCUMULATED DEPRECIATION	(3,457)	(2,483)
	29,743	25,947
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,840	4,436
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	—	17
GOODWILL	6,419	4,729
INTANGIBLE ASSETS, net	2,087	1,568
OTHER NON-CURRENT ASSETS, net	693	766
Total assets	$48,221	$43,702

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2014	2013
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$2,992	$3,627
Accounts payable to related companies	62	45
Exchanges payable	183	285
Price risk management liabilities	21	45
Accrued and other current liabilities	1,774	1,428
Current maturities of long-term debt	1,008	637
Total current liabilities	6,040	6,067
LONG-TERM DEBT, less current maturities	18,332	16,451
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	138	54
DEFERRED INCOME TAXES	4,226	3,762
OTHER NON-CURRENT LIABILITIES	1,206	1,080
COMMITMENTS AND CONTINGENCIES (Note 11)		
REDEEMABLE NONCONTROLLING INTERESTS	15	—
EQUITY:		
General Partner	184	171
Limited Partners:		
Common Unitholders (355,510,227 and 333,826,372 units authorized, issued and outstanding as of December 31, 2014 and 2013, respectively)	10,430	9,797
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary)	—	—
Class G Unitholders (90,706,000 units authorized, issued and outstanding – held by subsidiary)	—	—
Class H Unitholders (50,160,000 units authorized, issued and outstanding)	1,512	1,511
Accumulated other comprehensive income (loss)	(56)	61
Total partners' capital	12,070	11,540
Noncontrolling interest	6,194	4,748
Total equity	18,264	16,288
Total liabilities and equity	$48,221	$43,702

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)

	Years Ended December 31,		
	2014	2013	2012
REVENUES:			
Natural gas sales	$3,561	$3,165	$2,387
NGL sales	4,293	2,817	1,718
Crude sales	16,416	15,477	2,872
Gathering, transportation and other fees	2,553	2,590	2,007
Refined product sales	19,437	18,479	5,299
Other	4,898	3,811	1,419
Total revenues	51,158	46,339	15,702
COSTS AND EXPENSES:			
Cost of products sold	45,540	41,204	12,266
Operating expenses	1,636	1,441	953
Depreciation and amortization	1,130	1,032	656
Selling, general and administrative	377	432	433
Goodwill impairment	—	689	—
Total costs and expenses	48,683	44,798	14,308
OPERATING INCOME	2,475	1,541	1,394
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(860)	(849)	(665)
Equity in earnings of unconsolidated affiliates	234	172	142
Gain on deconsolidation of Propane Business	—	—	1,057
Gain on sale of AmeriGas common units	177	87	—
Loss on extinguishment of debt	—	—	(115)
Gains (losses) on interest rate derivatives	(157)	44	(4)
Non-operating environmental remediation	—	(168)	—
Other, net	(25)	5	11
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,844	832	1,820
Income tax expense from continuing operations	355	97	63
INCOME FROM CONTINUING OPERATIONS	1,489	735	1,757
Income (loss) from discontinued operations	64	33	(109)
NET INCOME	1,553	768	1,648
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	217	312	79
NET INCOME ATTRIBUTABLE TO PARTNERS	1,336	456	1,569
GENERAL PARTNER'S INTEREST IN NET INCOME	513	506	461
CLASS H UNITHOLDER'S INTEREST IN NET INCOME	217	48	—
COMMON UNITHOLDERS' INTEREST IN NET INCOME (LOSS)	$606	$(98)	$1,108
INCOME (LOSS) FROM CONTINUING OPERATIONS PER COMMON UNIT:			
Basic	$1.58	$(0.23)	$4.93
Diluted	$1.58	$(0.23)	$4.91
NET INCOME (LOSS) PER COMMON UNIT:			
Basic	$1.77	$(0.18)	$4.43

Diluted	$1.77	$(0.18)	$4.42

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2014	2013	2012
Net income	$1,553	$768	$1,648
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	3	(4)	(14)
Change in value of derivative instruments accounted for as cash flow hedges	—	(1)	8
Change in value of available-for-sale securities	1	2	—
Actuarial gain (loss) relating to pension and other postretirement benefits	(113)	66	(10)
Foreign currency translation adjustment	(2)	(1)	—
Change in other comprehensive income from unconsolidated affiliates	(6)	17	(9)
	(117)	79	(25)
Comprehensive income	1,436	847	1,623
Less: Comprehensive income attributable to noncontrolling interest	217	312	74
Comprehensive income attributable to partners	$1,219	$535	$1,549

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

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

		Limited Partners				
	General Partner	Common Unitholders	Class H Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2011	$182	$5,533	$—	$ 6	$ 629	$6,350
Distributions to partners	(454)	(889)	—	—	—	(1,343)
Distributions to noncontrolling interest	—	—	—	—	(233)	(233)
Units issued for cash	—	791	—	—	—	791
Capital contributions from noncontrolling interest	—	—	—	—	343	343
Sunoco Merger (see Note 3)	—	2,288	—	—	3,580	5,868
ETP Holdco Transaction (see Note 3)	—	165	—	—	3,748	3,913
Issuance of units in other acquisitions (excluding Sunoco, Inc.)	—	7	—	—	—	7
Other comprehensive loss, net of tax	—	—	—	(19)	(6)	(25)
Other, net	(1)	23	—	—	(9)	13
Net income	461	1,108	—	—	79	1,648
Balance, December 31, 2012	188	9,026	—	(13)	8,131	17,332
Distributions to partners	(523)	(1,228)	(51)	—	—	(1,802)
Distributions to noncontrolling interest	—	—	—	—	(382)	(382)
Units issued for cash	—	1,611	—	—	—	1,611
Issuance of Class H Units (see Note 8)	—	(1,514)	1,514	—	—	—
Capital contributions from noncontrolling interest	—	—	—	—	137	137
ETP Holdco Acquisition and SUGS Contribution (see Note 3)	—	2,013	—	(5)	(3,448)	(1,440)
Other comprehensive income, net of tax	—	—	—	79	—	79
Other, net	—	(13)	—	—	(2)	(15)
Net income (loss)	506	(98)	48	—	312	768
Balance, December 31, 2013	171	9,797	1,511	61	4,748	16,288
Distributions to partners	(500)	(1,252)	(212)	—	—	(1,964)
Distributions to noncontrolling interest	—	—	—	—	(362)	(362)
Units issued for cash	—	1,382	—	—	—	1,382
Subsidiary units issued for cash	1	174	—	—	1,069	1,244
Capital contributions from noncontrolling interest	—	—	—	—	161	161

Lake Charles LNG Transaction (see Note 3)	—	(1,167)	—	—	—	(1,167)
Susser Merger (see Note 3)	—	908	—	—	626	1,534
Sunoco Logistics acquisition of a noncontrolling interest	(1)	(79)	—	—	(245)	(325)
Other comprehensive loss, net of tax	—	—	—	(117)	—	(117)
Other, net	—	61	(4)	—	(20)	37
Net income	513	606	217	—	217	1,553
Balance, December 31, 2014	$184	$10,430	$1,512	$ (56)	$ 6,194	$18,264

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$1,553	$768	$1,648
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	1,130	1,032	656
Deferred income taxes	(47)	48	62
Amortization included in interest expense	(61)	(80)	(35)
Inventory valuation adjustments	473	(3)	75
Non-cash compensation expense	58	47	42
Goodwill impairment	—	689	—
Gain on sale of AmeriGas common units	(177)	(87)	—
Gain on deconsolidation of Propane Business	—	—	(1,057)
Gain on curtailment of other postretirement benefits	—	—	(15)
Loss on extinguishment of debt	—	—	115
Write-down of assets included in loss from discontinued operations	—	—	132
Distributions on unvested awards	(16)	(12)	(8)
Equity in earnings of unconsolidated affiliates	(234)	(172)	(142)
Distributions from unconsolidated affiliates	203	247	132
Other non-cash	(60)	42	68
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(264)	(146)	(475)
Net cash provided by operating activities	2,558	2,373	1,198
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Susser Merger, net of cash received (see Note 3)	(808)	—	—
Cash paid for acquisition of a noncontrolling interest	(325)	—	—
Cash paid for ETP Holdco Acquisition (See Note 3)	—	(1,332)	—
Cash paid for Citrus Merger	—	—	(1,895)
Cash proceeds from the sale of AmeriGas common units	814	346	—
Cash proceeds from SUGS Contribution (See Note 3)	—	504	—
Cash proceeds from contribution and sale of propane operations	—	—	1,443
Cash (paid) received from all other acquisitions	(429)	(405)	531
Capital expenditures (excluding allowance for equity funds used during construction)	(4,158)	(2,575)	(2,840)
Contributions in aid of construction costs	45	52	35
Contributions to unconsolidated affiliates	(170)	(1)	(30)
Distributions from unconsolidated affiliates in excess of cumulative earnings	151	217	130
Proceeds from sale of discontinued operations	77	1,008	207
Proceeds from the sale of assets	50	53	18
Change in restricted cash	172	(348)	5
Other	(17)	21	111
Net cash used in investing activities	(4,598)	(2,460)	(2,285)

The accompanying notes are an integral part of these consolidated financial statements.
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CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	9,909	8,001	8,208
Repayments of long-term debt	(8,223)	(7,016)	(6,598)
Proceeds from borrowings from affiliates	—	—	221
Repayments of borrowings from affiliates	—	(166)	(55)
Net proceeds from issuance of Common Units	1,382	1,611	791
Subsidiary equity offerings, net of issuance costs	1,244	—	—
Capital contributions received from noncontrolling interest	174	147	320
Distributions to partners	(1,964)	(1,802)	(1,343)
Distributions to noncontrolling interest	(362)	(382)	(233)
Debt issuance costs	(30)	(32)	(20)
Other	—	(36)	—
Net cash provided by financing activities	2,130	325	1,291
INCREASE IN CASH AND CASH EQUIVALENTS	90	238	204
CASH AND CASH EQUIVALENTS, beginning of period	549	311	107
CASH AND CASH EQUIVALENTS, end of period	$639	$549	$311

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

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

1. OPERATIONS AND ORGANIZATION:

The consolidated financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries (the "Partnership," "we" or "ETP") presented herein for the years ended December 31, 2014, 2013 and 2012, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and subsidiaries we control, even if we do not have a majority ownership. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through the date the financial statements were issued.

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these assets.

Certain prior period amounts have been reclassified to conform to the 2014 presentation. These reclassifications had no impact on net income or total equity.

We are managed by our general partner, ETP GP, which is in turn managed by its general partner, ETP LLC. ETE, a publicly traded master limited partnership, owns ETP LLC, the general partner of our General Partner. The consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

Our consolidated subsidiary, Susser Petroleum Partners LP, changed its name in October 2014 to Sunoco LP. Additionally, Trunkline LNG Company, LLC, a consolidated subsidiary of ETE, changed its name in September 2014 to Lake Charles LNG Company, LLC. All references to these entities throughout this document reflect the new name of these entities, regardless of whether the disclosure relates to periods or events prior to the dates of the name changes.

Business Operations

Our activities are primarily conducted through our operating subsidiaries (collectively, the "Operating Companies") as follows:

- ETC OLP, a Texas limited partnership primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. ETC OLP's intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP's midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
  - Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
  - ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
  - ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
  - CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

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- ETP Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco, Inc. Panhandle and Sunoco, Inc. operations are described as follows:
- Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. As discussed in Note 3, in January 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, with Panhandle surviving the merger.
- Sunoco, Inc. owns and operates retail marketing assets, which sell gasoline and middle distillates at retail locations and operates convenience stores primarily on the east coast and in the midwest region of the United States. Effective June 1, 2014, the Partnership combined certain Sunoco, Inc. retail assets with another wholly-owned subsidiary of ETP to form a limited liability company owned by ETP and Sunoco, Inc.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of products, crude oil and NGL pipelines, terminalling and storage assets, and refined products, crude oil and NGL acquisition and marketing assets.
- ETP owns an indirect 100% equity interest in Susser and the general partner interest, incentive distribution rights and a 42.8% limited partner interest in Sunoco LP. Susser operates convenience stores in Texas, New Mexico and Oklahoma. Sunoco LP distributes motor fuels to convenience stores and retail fuel outlets in Texas, New Mexico, Oklahoma, Kansas and Louisiana and other commercial customers. As discussed in Note 3, in October 2014, Sunoco LP acquired MACS from ETP. These operations are reported within the retail marketing segment.

Our financial statements reflect the following reportable business segments:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- liquids transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in

exchange for those goods or services.

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ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity ("ASU 2014-08"), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity's operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

Revenue Recognition

Revenues for sales of natural gas and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenues from service labor, transportation, treating, compression and gas processing are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available.

Our intrastate transportation and storage and interstate transportation 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. Fuel retained for a fee is typically valued at market prices.

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from 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, (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, (iv) purchasing all or a specified percentage of natural gas and/or NGL delivered from producers and treating or processing our plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing obligations. In many cases, we provide services

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under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

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

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.

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.

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. A portion of our gasoline and diesel sales are to wholesale customers on a consignment basis, in which we retain title to inventory, control access to and sale of fuel inventory, and recognize revenue at the time the fuel is sold to the ultimate customer. We typically own the fuel dispensing equipment and underground storage tanks at consignment sites, and in some cases we own the entire site and have entered into an operating lease with the wholesale customer operating the site. In addition, our retail outlets derive other income from lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rental and other ancillary product and service offerings. Some of Sunoco, Inc.’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 recorded on a net commission basis and 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 Accounting – 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 these entities, 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.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

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Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

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

	Years Ended December 31,		
	2014	2013	2012
Accounts receivable	$547	$(458)	$300
Accounts receivable from related companies	(45)	(17)	(50)
Inventories	79	(256)	(253)
Exchanges receivable	6	(24)	11
Other current assets	120	(56)	571
Other non-current assets, net	(6)	(22)	(53)
Accounts payable	(804)	525	(979)
Accounts payable to related companies	20	(122)	100
Exchanges payable	(100)	131	—
Accrued and other current liabilities	(118)	152	(151)
Other non-current liabilities	(75)	151	25
Price risk management assets and liabilities, net	112	(150)	4
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$(264)	$(146)	$(475)

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

	Years Ended December 31,		
	2014	2013	2012
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$541	$167	$359
Net gains from subsidiary common unit issuances	$175	$—	$—
Regency common and Class F units received in exchange for contribution of SUGS	$—	$961	$—
AmeriGas limited partner interest received in exchange for contribution of Propane Business	$—	$—	$1,123
NON-CASH FINANCING ACTIVITIES:			
Issuance of Common Units in connection with the Susser Merger (see Note 3)	$908	$—	$—
Redemption of Common Units in connection with the Lake Charles LNG Transaction (see Note 3)	$1,167	$—	$—
Issuance of Common Units in connection with the ETP Holdco Acquisition	$—	$2,464	$—
Issuance of Class H Units	$—	$1,514	$—
Issuance of Common Units in connection with other acquisitions	$—	$—	$2,295
Contributions receivable related to noncontrolling interest	$—	$13	$23
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$929	$903	$678
Cash paid for income taxes	$343	$57	$22

Accounts Receivable

Our midstream, NGL and intrastate transportation and storage operations deal with a variety of counterparties across the energy sector, some of which are investment grade, and most of which are not. Internal credit ratings and credit limits are assigned for all counterparties and limits are monitored against credit exposure. Letters of credit or prepayments may be required from those counterparties that are not investment grade depending on the internal credit rating and level of commercial activity with the counterparty. Master setoff agreements are put in place with counterparties where appropriate to mitigate risk. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible.

Our investment in Sunoco Logistics segment extends credit terms to certain customers after review of various credit indicators, including the customer's credit rating. Based on that review, a letter of credit or other security may be required. Outstanding customer receivable balances are regularly reviewed for possible non-payment indicators and reserves are recorded for doubtful accounts based upon management's estimate of collectability at the time of review. Actual balances are charged against the reserve when all collection efforts have been exhausted.

Our interstate transportation and storage operations have a concentration of customers in the electric and gas utility industries, municipalities, as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Our interstate transportation and storage operations establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and consider many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

Our retail marketing segment extends credit to customers after a review of various credit indicators. Depending on the type of customer and its risk profile, security in the form of a cash deposit, letter of credit or mortgages may be required. Management records reserves for bad debt by computing a proportion of average write-off activity over the

past five years in comparison to the outstanding balance in accounts receivable. This proportion is then applied to the accounts receivable balance at the end of the reporting period to calculate a current estimate of what is uncollectible. The allowance computation may then be adjusted to reflect input provided by the credit department and business line managers who may have specific knowledge of

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uncollectible items. The credit department and business line managers make the decision to write off an account, based on understanding of the potential collectability.

We enter into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

Inventories

Inventories consist principally of natural gas held in storage, crude oil, petroleum and chemical products. Natural gas held in storage is valued at the lower of cost or market utilizing the weighted-average cost method. The cost of crude oil and petroleum and chemical products is determined using the last-in, first out method. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31,	
	2014	2013
Natural gas and NGLs	$369	$573
Crude oil	364	488
Refined products	392	543
Appliances, parts and fittings, and other	264	161
Total inventories	$1,389	$1,765

During the year ended December 31, 2014, the Partnership recorded write-downs of $473 million on its crude oil, refined products and NGL inventories as a result of a decline in the market price of these products. The write-down was calculated based upon current replacement costs.

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Exchanges

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

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2014	2013
Deposits paid to vendors	$65	$49
Deferred income taxes	14	—
Prepaid expenses and other	192	261
Total other current assets	$271	$310

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. 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

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labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our consolidated statements of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value.

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

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

	December 31,	
	2014	2013
Land and improvements	$1,173	$878
Buildings and improvements (1 to 45 years)	1,868	900
Pipelines and equipment (5 to 83 years)	19,274	16,966
Natural gas and NGL storage facilities (5 to 46 years)	1,215	1,083
Bulk storage, equipment and facilities (2 to 83 years)	2,583	1,933
Tanks and other equipment (5 to 40 years)	35	1,685
Retail equipment (2 to 99 years)	515	450
Vehicles (1 to 25 years)	158	124
Right of way (20 to 83 years)	2,059	1,901
Furniture and fixtures (2 to 25 years)	53	48
Linepack	117	116
Pad gas	44	52
Other (1 to 30 years)	919	626
Construction work-in-process	3,187	1,668
	33,200	28,430
Less – Accumulated depreciation	(3,457)	(2,483)
Property, plant and equipment, net	$29,743	$25,947

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

	Years Ended December 31,		
	2014	2013	2012
Depreciation expense	$1,026	$944	$615
Capitalized interest, excluding AFUDC	$99	$43	$99

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of August 31 for subsidiaries in our intrastate transportation and storage and midstream segments and during the fourth quarter for subsidiaries in our interstate transportation and storage, liquids

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transportation and services, and retail marketing segments and all others. We recorded goodwill impairments for the periods presented in these consolidated financial statements.

Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	Liquids Transportation and Services	Investment in Sunoco Logistics	Retail Marketing	All Other	Total
Balance, December 31, 2012	$ 10	$1,884	$375	$ 432	$1,368	$1,272	$265	$5,606
Goodwill acquired	—	—	—	—	—	156	—	156
Goodwill disposed	—	—	(337)	—	—	—	—	(337)
Goodwill impairment	—	(689)	—	—	—	—	—	(689)
Other	—	—	(2)	—	(22)	17	—	(7)
Balance, December 31, 2013	10	1,195	36	432	1,346	1,445	265	4,729
Goodwill acquired	—	—	—	—	12	1,862	—	1,874
Goodwill disposed	—	(184)	—	—	—	—	—	(184)
Balance, December 31, 2014	$ 10	$1,011	$36	$ 432	$1,358	$3,307	$265	$6,419

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. We recorded a net increase in goodwill of $1.69 billion during the year ended December 31, 2014 primarily due to $1.73 billion related to the Susser Merger.

During the fourth quarter of 2013, we performed a goodwill impairment test on our Lake Charles 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 Lake Charles 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 Lake Charles 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 Lake Charles 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.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

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Components and useful lives of intangible assets were as follows:

	December 31, 2014		December 31, 2013	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$1,482	$(267)	$1,393	$(164)
Patents (9 years)	48	(11)	48	(6)
Trade Names (15 years)	490	—	—	—
Other (1 to 15 years)	36	(7)	4	(1)
Total amortizable intangible assets	$2,056	$(285)	$1,445	$(171)
Non-amortizable intangible assets:				
Trademarks	316	—	294	—
Total intangible assets	$2,372	$(285)	$1,739	$(171)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2014	2013	2012
Reported in depreciation and amortization	$104	$88	$36

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

Years Ending December 31:	
2015	$128
2016	125
2017	125
2018	124
2019	121

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Other Non-Current Assets, net

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

	December 31,	
	2014	2013
Unamortized financing costs (3 to 30 years)	$63	$70
Regulatory assets	85	86
Deferred charges	220	144
Restricted funds	177	378
Other	148	88
Total other non-current assets, net	$693	$766

Restricted funds primarily consisted of restricted cash held in our wholly-owned captive insurance companies.

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Asset Retirement Obligations

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 certain amounts recorded by Panhandle, Sunoco Logistics and our retail marketing operations, discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2014 and 2013, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle'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, Inc. has legal asset retirement obligations for several other assets at its previously owned 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, Inc. 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.

Below is a schedule of AROs by segment recorded as other non-current liabilities in ETP's consolidated balance sheet:

	December 31,	
	2014	2013
Interstate transportation and storage	$58	$55
Investment in Sunoco Logistics	41	41
Retail marketing	87	84
	$186	$180

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, 2014, there were no legally restricted funds for the purpose of settling AROs.

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Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2014	2013
Interest payable	$301	$294
Customer advances and deposits	82	126
Accrued capital expenditures	536	166
Accrued wages and benefits	196	155
Taxes payable other than income taxes	236	214
Income taxes payable	50	3
Deferred income taxes	99	119
Other	274	351
Total accrued and other current liabilities	$1,774	$1,428

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2014 was $20.40 billion and $19.34 billion, respectively. As of December 31, 2013, the aggregate fair value and carrying amount of our debt obligations was $17.69 billion and $17.09 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have 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 OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the period ended December 31, 2014, no transfers were made between any levels within the fair value hierarchy.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2014 and 2013 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at December 31, 2014	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$3	$—	$3
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	19	19	—
Swing Swaps IFERC	26	1	25
Fixed Swaps/Futures	541	541	—
Forward Physical Swaps	1	—	1
Power:			
Forwards	3	—	3
Futures	4	4	—
Natural Gas Liquids – Forwards/Swaps	46	46	—
Refined Products – Futures	21	21	—
Total commodity derivatives	661	632	29
Total assets	$664	$632	$32
Liabilities:			
Interest rate derivatives	$(155)	$—	$(155)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(18)	(18)	—
Swing Swaps IFERC	(25)	(2)	(23)
Fixed Swaps/Futures	(490)	(490)	—
Power:			
Forwards	(4)	—	(4)
Futures	(2)	(2)	—
Natural Gas Liquids – Forwards/Swaps	(32)	(32)	—
Refined Products – Futures	(7)	(7)	—
Total commodity derivatives	(578)	(551)	(27)
Total liabilities	$(733)	$(551)	$(182)

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	Fair Value Total	Fair Value Measurements at December 31, 2013	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$47	$—	$47
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	5	5	—
Swing Swaps IFERC	8	1	7
Fixed Swaps/Futures	201	201	—
Power:			
Forwards	3	—	3
Natural Gas Liquids – Forwards/Swaps	5	5	—
Refined Products – Futures	5	5	—
Total commodity derivatives	227	217	10
Total assets	$274	$217	$57
Liabilities:			
Interest rate derivatives	$(95)	$—	$(95)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(4)	(4)	—
Swing Swaps IFERC	(6)	—	(6)
Fixed Swaps/Futures	(201)	(201)	—
Forward Physical Swaps	(1)	—	(1)
Power:			
Forwards	(1)	—	(1)
Natural Gas Liquids – Forwards/Swaps	(5)	(5)	—
Refined Products – Futures	(5)	(5)	—
Total commodity derivatives	(223)	(215)	(8)
Total liabilities	$(318)	$(215)	$(103)

At December 31, 2013, the fair value of the Lake Charles LNG reporting unit was classified as Level 3 of the fair value hierarchy due to the significance of unobservable inputs developed using company-specific information. We used the income approach to measure the fair value of the Lake Charles LNG reporting unit. Under the income approach, we calculated the fair value based on the present value of the estimated future cash flows. The discount rate used, which was an unobservable input, was based on the weighted-average cost of capital adjusted for the relevant risk associated with business-specific characteristics and the uncertainty related to the business's ability to execute on the projected cash flows.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs (“CIAC”) are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

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Shipping and Handling Costs

Shipping and handling costs are included in cost of products sold, except for shipping and handling costs related to fuel consumed for compression and treating which are included in operating expenses.

Costs and Expenses

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

We record the collection of taxes to be remitted to government authorities on a net basis except for our retail marketing segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income (loss). Excise taxes collected by our retail marketing segment were $2.46 billion, $2.22 billion and $573 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Income Taxes

ETP is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Second Amended and Restated Agreement of Limited Partnership (the “Partnership Agreement”).

As a publicly traded limited partnership, we are subject to a statutory requirement that our “qualifying income” (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, ETP would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2014, 2013 and 2012, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. These corporate subsidiaries include Susser and ETP Holdco, which owns Sunoco, Inc. and Panhandle.

The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be

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measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity 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 statements 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 statements of operations.

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

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

Unit-Based Compensation

For awards of restricted units, we recognize compensation expense over the vesting period based on the grant-date fair value, which is determined based on the market price of our Common Units on the grant date. For awards of cash restricted units, we remeasure the fair value of the award at the end of each reporting period based on the market price of our Common Units as of the reporting date, and the fair value is recorded in other non-current liabilities on our consolidated balance sheets.

Pensions and Other Postretirement Benefit Plans

Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through AOCI in equity or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements.

Our net income for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

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3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

Pending Transaction

Regency Merger

In January 2015, ETP and Regency entered into a definitive merger agreement, as amended on February 18, 2015 (the "Merger Agreement"), pursuant to which Regency will merge with a wholly-owned subsidiary of ETP, with Regency continuing as the surviving entity and becoming a wholly-owned subsidiary of ETP (the "Regency Merger"). At the effective time of the Regency Merger (the "Effective Time"), each Regency common unit and Class F unit will be converted into the right to receive 0.4066 ETP Common Units, plus a number of additional ETP Common Units equal to $0.32 per Regency common unit divided by the lesser of (i) the volume weighted average price of ETP Common Units for the five trading days ending on the third trading day immediately preceding the Effective Time and (ii) the closing price of ETP Common Units on the third trading day immediately preceding the Effective Time, rounded to the nearest ten thousandth of a unit. Each Regency series A preferred unit will be converted into the right to receive a preferred unit representing a limited partner interest in ETP, a new class of units in ETP to be established at the Effective Time. The transaction is subject to other customary closing conditions including approval by Regency's unitholders.

In addition, ETE, which owns the general partner and 100% of the incentive distribution rights of both Regency and ETP, has agreed to reduce the incentive distributions it receives from ETP by a total of $320 million over a five year period. The IDR subsidy will be $80 million in the first year post closing and $60 million per year for the following four years. The transaction is expected to close in the second quarter of 2015.

ETP and Regency are under common control of ETE; therefore, we expect to account for the Regency Merger at historical cost as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements will be retrospectively adjusted to reflect consolidation of Regency beginning May 26, 2010 (the date ETE acquired Regency's general partner).

2014 Transactions

Susser Merger

In August 2014, ETP and Susser completed the merger of an indirect wholly-owned subsidiary of ETP, with and into Susser, with Susser surviving the merger as a subsidiary of ETP for total consideration valued at approximately $1.8 billion (the "Susser Merger"). The total consideration paid in cash was approximately $875 million and the total consideration paid in equity was approximately 15.8 million ETP Common Units. The Susser Merger broadens our retail geographic footprint and provides synergy opportunities and a platform for future growth.

In connection with the Susser Merger, ETP acquired an indirect 100% equity interest in Susser and the general partner interest and the incentive distribution rights in Sunoco LP, approximately 11 million Sunoco LP common and subordinated units, and Susser's existing retail operations, consisting of 630 convenience store locations.

Effective with the closing of the transaction, Susser ceased to be a publicly traded company and its common stock discontinued trading on the NYSE.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Susser Merger using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Our consolidated balance sheet as of December 31, 2014 reflected the preliminary purchase price allocations based on available information. Management is reviewing the valuation and confirming the results to determine the final purchase price allocation.

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

	Susser
Total current assets	$446
Property, plant and equipment	1,069
Goodwill[1]	1,734
Intangible assets	611
Other non-current assets	17
	3,877
Total current liabilities	377
Long-term debt, less current maturities	564
Deferred income taxes	488
Other non-current liabilities	39
Noncontrolling interest	626
	2,094
Total consideration	1,783
Cash received	67
Total consideration, net of cash received	$1,716

[1] None of the goodwill is expected to be deductible for tax purposes.

The fair values of the assets acquired and liabilities assumed is being determined using various valuation techniques, including the income and market approaches.

ETP incurred merger related costs related to the Susser Merger of $25 million during the year ended December 31, 2014. Our consolidated statements of operations for the year ended December 31, 2014 reflected revenue and net income related to Susser of $2.32 billion and $105 million, respectively.

No pro forma information has been presented, as the impact of these acquisitions was not material in relation to ETP's consolidated results of operations.

MACS to Sunoco LP

In October 2014, Sunoco LP acquired MACS from a subsidiary of ETP in a transaction valued at approximately $768 million (the "MACS Transaction"). The transaction included approximately 110 company-operated retail convenience stores and 200 dealer-operated and consignment sites from MACS, which had originally been acquired by ETP in October 2013. The consideration paid by Sunoco LP consisted of approximately 4 million Sunoco LP common units issued to ETP and $556 million in cash, subject to customary closing adjustments. Sunoco LP initially financed the cash portion by utilizing availability under its revolving credit facility. In October 2014 and November 2014, Sunoco LP partially repaid borrowings on its revolving credit facility with aggregate net proceeds of $405 million from a public offering of 9.1 million Sunoco LP common units.

Lake Charles LNG Transaction

On February 19, 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE (the "Lake Charles LNG Transaction"). This transaction was effective as of January 1, 2014, at which time ETP deconsolidated Lake Charles LNG, including goodwill of $184 million and intangible assets of $50 million related to Lake Charles LNG. The results of Lake Charles LNG's operations have not been presented as discontinued operations and Lake Charles LNG's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements due to the continuing involvement among the entities.

In connection with ETE's acquisition of Lake Charles LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year

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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, as discussed further in Note 8.

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle at the time of the merger, and PEPL Holdings, a wholly-owned subsidiary of Southern Union and the sole limited partner of Panhandle at the time of the merger, 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 material operations of its own, other than its ownership of Panhandle and noncontrolling interests in PEI Power II, LLC, Regency (31.4 million common units and 6.3 million Class 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.

2013 Transactions

Sale of Southern Union's Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri agreed to acquire the assets of Southern Union's MGE division and Laclede Massachusetts agreed to acquire the assets of Southern Union's NEG division (together, the "LDC Disposal Group"). Laclede Gas Company, a subsidiary of The Laclede Group, Inc., subsequently assumed all of Laclede Missouri's rights and obligations under the purchase and sale agreement. In February 2013, The Laclede Group, Inc. entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that allowed a subsidiary of APUC to assume the rights of The Laclede Group, Inc. to purchase the assets of Southern Union's NEG division.

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.

The LDC Disposal Group's operations have been classified as discontinued operations for all periods in the consolidated statements of operations.

The following table summarizes selected financial information related to Southern Union's distribution operations in 2013 through MGE and NEG's sale dates in September 2013 and December 2013, respectively, and for the period from March 26, 2012 to December 31, 2012:

	Years Ended December 31,	
	2013	2012
Revenue from discontinued operations	$415	$324
Net income of discontinued operations, excluding effect of taxes and overhead allocations	65	43

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. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. 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. The Partnership has not presented SUGS as discontinued operations due to the Partnership's

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continuing involvement with SUGS through affiliate relationships, as well as the direct investment in Regency common and Class F units received, which has been accounted for using the equity method.

Acquisition of ETE's ETP Holdco Interest

On April 30, 2013, ETP acquired ETE's 60% interest in ETP 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 "ETP Holdco Acquisition"). As a result, ETP now owns 100% of ETP 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 ETP Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

2012 Transactions

Southern Union Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union was the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE. See below for discussion of ETP Holdco Transaction and ETE's contribution of Southern Union to ETP Holdco.

Under the terms of the merger agreement, Southern Union stockholders received a total of 57 million ETE Common Units and a total of approximately $3.01 billion in cash. Effective with the closing of the transaction, Southern Union's common stock was no longer publicly traded.

Citrus Acquisition

In connection with the Southern Union Merger on March 26, 2012, we completed our acquisition of CrossCountry, a subsidiary of Southern Union which owned an indirect 50% interest in Citrus, the owner of FGT. The total merger consideration was approximately $2.0 billion, consisting of approximately $1.9 billion in cash and approximately 2.2 million ETP Common Units. See Note 4 for more information regarding our equity method investment in Citrus.

Sunoco Merger

On October 5, 2012, ETP completed its merger with Sunoco, Inc. Under the terms of the merger agreement, Sunoco, Inc. shareholders received 55 million ETP Common Units and a total of approximately $2.6 billion in cash.

Sunoco, Inc. generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco, Inc. also owned a 2% general partner interest, 100% of the IDRs, and 32% of the outstanding common units of Sunoco Logistics. As discussed below, on October 5, 2012, Sunoco, Inc.'s interests in Sunoco Logistics were transferred to the Partnership.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco, Inc. completed the exit from its Northeast refining operations by contributing the refining assets at its Philadelphia refinery and various commercial contracts to PES, a joint venture with The Carlyle Group. Sunoco, Inc. also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook Industrial Complex continued to support operations at the Philadelphia refinery prior to commencement of the PES joint venture. Under the terms of the joint venture agreement, The Carlyle Group contributed cash in exchange for a 67% controlling interest in PES. In exchange for contributing its Philadelphia refinery assets and various commercial contracts to the joint venture, Sunoco, Inc. retained an approximate 33% non-operating noncontrolling interest. The fair value of Sunoco, Inc.'s retained interest in PES, which was $75 million on the date on which the joint venture was formed, was determined based on the equity contributions of The Carlyle Group. Sunoco, Inc. has indemnified PES for environmental liabilities related to the Philadelphia refinery that arose from the operation of such assets prior the formation of the joint venture. The Carlyle Group will oversee day-to-day operations of PES and the refinery. JPMorgan Chase provides working capital financing to PES in the form of an asset-backed loan, supply crude oil and other feedstocks to the refinery at the time of processing and purchase certain blendstocks and all finished refined products as they are processed. Sunoco, Inc. entered into a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

ETP incurred merger related costs related to the Sunoco Merger of $28 million during the year ended December 31, 2012. Sunoco, Inc.'s revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco, Inc.'s net loss included in our consolidated statement of operations was approximately $14 million during October through December 2012. Sunoco Logistics' revenue included in our

consolidated statement of

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operations was approximately $3.11 billion during October through December 2012. Sunoco Logistics' net income included in our consolidated statement of operations was approximately $145 million during October through December 2012.

ETP Holdco Transaction

Immediately following the closing of the Sunoco Merger in 2012, ETE contributed its interest in Southern Union into ETP Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in ETP Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco, Inc. to ETP Holdco and retained a 40% equity interest in ETP Holdco. Prior to the contribution of Sunoco, Inc. to ETP Holdco, Sunoco, Inc. contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90.7 million Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units were exchanged for Class G Units in 2013 as discussed in Note 8.

Pursuant to a stockholders agreement between ETE and ETP, ETP controlled ETP Holdco (prior to ETP's acquisition of ETE's 60% equity interest in ETP Holdco in 2013) and therefore, ETP consolidated ETP Holdco (including Sunoco, Inc. and Southern Union) in its financial statements subsequent to consummation of the ETP Holdco Transaction.

Under the terms of the ETP Holdco transaction agreement, 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.

In accordance with GAAP, we have accounted for the ETP 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). This change only impacted interim periods in 2012, and no prior annual amounts have been adjusted.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Sunoco Merger using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Upon consummation of the ETP Holdco Transaction, we applied the accounting guidance for transactions between entities under common control. In doing so, we recorded the values of assets and liabilities that had been recorded by ETE as reflected below.

The following table summarizes the assets acquired and liabilities assumed as of the respective acquisition dates:

	Sunoco, Inc.[1]	Southern Union[2]
Current assets	$7,312	$556
Property, plant and equipment	6,686	6,242
Goodwill	2,641	2,497
Intangible assets	1,361	55
Investments in unconsolidated affiliates	240	2,023
Note receivable	821	—
Other assets	128	163
	19,189	11,536
Current liabilities	4,424	1,348
Long-term debt obligations, less current maturities	2,879	3,120
Deferred income taxes	1,762	1,419
Other non-current liabilities	769	284
Noncontrolling interest	3,580	—
	13,414	6,171
Total consideration	5,775	5,365
Cash received	2,714	37
Total consideration, net of cash received	$3,061	$5,328

[1] Includes amounts recorded with respect to Sunoco Logistics.

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(2) Includes ETP's acquisition of Citrus.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

As a result of the ETP Holdco Transaction, we recognized $38 million of merger-related costs during the year ended December 31, 2012 related to Southern Union. Southern Union's revenue included in our consolidated statement of operations was approximately $1.26 billion since the acquisition date to December 31, 2012. Southern Union's net income included in our consolidated statement of operations was approximately $39 million since the acquisition date to December 31, 2012.

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas common units. AmeriGas assumed approximately $71 million of existing HOLP debt. In connection with the closing of this transaction, we entered into a support agreement with AmeriGas pursuant to which we are obligated to provide contingent, residual support of $1.50 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.50 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

Our consolidated financial statements did not reflect the Propane Business as discontinued operations due to our continuing involvement in this business through our investment in AmeriGas that was transferred as consideration for the transaction.

In June 2012, we sold the remainder of our retail propane operations, consisting of our cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and we received net proceeds of approximately $43 million.

Sale of Canyon

In October 2012, we sold Canyon for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been restated to present Canyon's operations as discontinued operations. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $132 million during the year ended December 31, 2012. Canyon was previously included in our midstream segment.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the year ended December 31, 2012 are presented as if the Sunoco Merger and the ETP Holdco Transaction had been completed on January 1, 2012:

	Year Ended December 31, 2012
Revenues	$39,136
Net income	1,133
Net income attributable to partners	788
Basic net income per Limited Partner unit	$1.33
Diluted net income per Limited Partner unit	$1.33

The pro forma consolidated results of operations include adjustments to:

- include the results of Southern Union and Sunoco, Inc. beginning January 1, 2012;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting;
- include incremental interest expense related to the financing of ETP's proportionate share of the purchase price; and
- reflect noncontrolling interest related to ETE's 60% interest in ETP Holdco during the periods.

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

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4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Regency

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 (see Note 3). The consideration paid by Regency in connection with this transaction included approximately 31.4 million Regency common units, approximately 6.3 million Regency Class F units, the distribution of $463 million in cash to Southern Union, net of closing adjustments, and the payment of $30 million in cash to a subsidiary of ETP. This direct investment in Regency common and Class F units received has been accounted for using the equity method.

The carrying amount of our investment in Regency was $1.34 billion and $1.41 billion as of December 31, 2014 and 2013, respectively, and was reflected in our all other segment.

Citrus

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry, a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus, merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105 million of ETP Common Units (the “Citrus Acquisition”) to a subsidiary of ETE. As a result of the consummation of the Citrus Acquisition, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

We recorded our investment in Citrus at $2.0 billion, which exceeded our proportionate share of Citrus’ equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting. The carrying amount of our investment in Citrus was $1.82 billion and $1.89 billion as of December 31, 2014 and 2013, respectively, and was reflected in our interstate transportation and storage segment.

AmeriGas

As discussed in Note 3, on January 12, 2012, we received approximately 29.6 million AmeriGas common units in connection with the contribution of our propane operations. In the year ended 2013, we sold 7.5 million AmeriGas common units for net proceeds of $346 million, and in the year ended 2014 we sold approximately 18.9 million AmeriGas common units for net proceeds of $814 million. Net proceeds from these sales were used to repay borrowings under the ETP Credit Facility and general partnership purposes. Subsequent to the sales, the Partnership’s remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

FEP

We have a 50% interest in FEP, a 50/50 joint venture with KMP. FEP owns the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The carrying amount of our investment in FEP was $130 million and $144 million as of December 31, 2014 and 2013, respectively, and was reflected in our interstate transportation and storage segment.

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Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, FEP, AmeriGas, Citrus and Regency (on a 100% basis) for all periods presented:

	December 31,	
	2014	2013
Current assets	$1,514	$1,372
Property, plant and equipment, net	16,967	12,320
Other assets	9,708	6,478
Total assets	$28,189	$20,170
Current liabilities	$2,324	$1,455
Non-current liabilities	13,206	10,286
Equity	12,659	8,429
Total liabilities and equity	$28,189	$20,170

	Years Ended December 31,		
	2014	2013	2012
Revenue	$9,467	$6,806	$4,057
Operating income	841	1,043	635
Net income	279	574	338

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

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5. NET INCOME PER LIMITED PARTNER UNIT:

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

	Years Ended December 31,		
	2014	2013	2012
Income from continuing operations	$1,489	$735	$1,757
Less: Income from continuing operations attributable to noncontrolling interest	217	296	62
Income from continuing operations, net of noncontrolling interest	1,272	439	1,695
General Partner's interest in income from continuing operations	513	505	463
Class H Unitholder's interest in income from continuing operations	217	—	—
Common Unitholders' interest in income (loss) from continuing operations	542	(66)	1,232
Additional earnings allocated (to) from General Partner	(4)	(2)	1
Distributions on employee unit awards, net of allocation to General Partner	(13)	(10)	(9)
Income (loss) from continuing operations available to Common Unitholders	$525	$(78)	$1,224
Weighted average Common Units – basic	331.5	343.4	248.3
Basic income (loss) from continuing operations per Common Unit	$1.58	$(0.23)	$4.93
Dilutive effect of unvested Unit Awards	1.3	—	0.7
Weighted average Common Units, assuming dilutive effect of unvested Unit Awards	332.8	343.4	249.0
Diluted income (loss) from continuing operations per Common Unit	$1.58	$(0.23)	$4.91
Basic income (loss) from discontinued operations per Common Unit	$0.19	$0.05	$(0.50)
Diluted income (loss) from discontinued operations per Common Unit	$0.19	$0.05	$(0.50)

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2014	2013
ETP Debt		
8.5% Senior Notes due April 15, 2014	$—	$292
5.95% Senior Notes due February 1, 2015	750	750
6.125% Senior Notes due February 15, 2017	400	400
6.7% Senior Notes due July 1, 2018	600	600
9.7% Senior Notes due March 15, 2019	400	400
9.0% Senior Notes due April 15, 2019	450	450
4.15% Senior Notes due October 1, 2020	700	700
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
3.60% Senior Notes due February 1, 2023	800	800
4.9% Senior Notes due February 1, 2024	350	350
7.6% Senior Notes due February 1, 2024	277	277
8.25% Senior Notes due November 15, 2029	267	267
6.625% Senior Notes due October 15, 2036	400	400
7.5% Senior Notes due July 1, 2038	550	550

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6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	450
5.95% Senior Notes due October 1, 2043	450	450
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
ETP $2.5 billion Revolving Credit Facility due October 27, 2019	570	65
Unamortized premiums, discounts and fair value adjustments, net	(1)	(34)
	11,459	11,213
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	—	88
5.54% Senior Notes due November 17, 2016	125	125
5.64% Senior Notes due May 24, 2017	82	82
5.36% Senior Notes due December 9, 2020	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Unamortized premiums, discounts and fair value adjustments, net	(1)	(1)
	781	869
Panhandle Debt[1]		
6.20% Senior Notes due November 1, 2017	300	300
7.00% Senior Notes due June 15, 2018	400	400
8.125% Senior Notes due June 1, 2019	150	150
7.60% Senior Notes due February 1, 2024	82	82
7.00% Senior Notes due July 15, 2029	66	66
8.25% Senior Notes due November 14, 2029	33	33
Floating Rate Junior Subordinated Notes due November 1, 2066	54	54
Unamortized premiums, discounts and fair value adjustments, net	99	155
	1,184	1,240
Sunoco, Inc. Debt		
4.875% Senior Notes due October 15, 2014	—	250
9.625% Senior Notes due April 15, 2015	250	250
5.75% Senior Notes due January 15, 2017	400	400
9.00% Debentures due November 1, 2024	65	65
Unamortized premiums, discounts and fair value adjustments, net	35	70
	750	1,035
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014[2]	—	175
6.125% Senior Notes due May 15, 2016	175	175
5.50% Senior Notes due February 15, 2020	250	250
4.65% Senior Notes due February 15, 2022	300	300
3.45% Senior Notes due January 15, 2023	350	350
4.25% Senior Notes due April 1, 2024	500	—
6.85% Senior Notes due February 15, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350

5.30% Senior Notes due April 1, 2044	700	—

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5.35% Senior Notes due May 15, 2045	800	—
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015[3]	35	35
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 19, 2018	150	200
Unamortized premiums, discounts and fair value adjustments, net	100	118
	4,260	2,503
Sunoco LP Debt		
Sunoco LP $1.25 billion Revolving Credit Facility due September 25, 2019	683	—
	683	—
Other	223	228
	19,340	17,088
Less: current maturities	1,008	637
	$18,332	$16,451

(1) In connection with the Panhandle Merger, Southern Union's debt obligations were assumed by Panhandle.

(2) Sunoco Logistics' 8.75% senior notes due February 15, 2014 were classified as long-term debt as Sunoco Logistics repaid these notes in February 2014 with borrowings under its $1.50 billion credit facility due November 2018.

(3) The Sunoco Logistics $35 million credit facility outstanding amounts were classified as long-term debt as Sunoco Logistics has the ability and intent to refinance such borrowings on a long-term basis.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $232 million in unamortized net premiums and fair value adjustments:

2015	$1,050
2016	314
2017	1,228
2018	1,155
2019	2,259
Thereafter	13,102
Total	$19,108

ETP as Co-Obligor of Sunoco, Inc. Debt

In connection with the Sunoco Merger and ETP Holdco Transaction, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco, Inc.'s existing senior notes and debentures. The balance of these notes was $715 million as of December 31, 2014.

ETP Senior Notes

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

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

Transwestern Senior Notes

The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

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Panhandle Junior Subordinated Notes

The interest rate on the remaining portion of Panhandle's junior subordinated notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the junior subordinated notes was $54 million at an effective interest rate of 3.26% at December 31, 2014.

Sunoco Logistics Senior Notes Offerings

In April 2014, Sunoco Logistics issued $300 million aggregate principal amount of 4.25% senior notes due April 2024 and $700 million aggregate principal amount of 5.30% senior notes due April 2044.

In November 2014, Sunoco Logistics issued $200 million aggregate principal amount of 4.25% senior notes due April 2024 and $800 million aggregate principal amount of 5.35% senior notes due May 2045. Sunoco Logistics used the net proceeds from the offerings to pay outstanding borrowings under the Sunoco Logistics Credit Facility and for general partnership purposes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2019. 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. In February 2015, ETP amended its revolving credit facility to increase the capacity to $3.75 billion.

As of December 31, 2014, the ETP Credit Facility had $570 million outstanding, and the amount available for future borrowings was $1.81 billion after taking into account letters of credit of $121 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 1.66%.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $1.50 billion unsecured credit facility (the "Sunoco Logistics Credit Facility") which matures in November 2018. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions.

The Sunoco Logistics Credit Facility is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The Sunoco Logistics Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. As of December 31, 2014, the Sunoco Logistics Credit Facility had $150 million of outstanding borrowings.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, maintains 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. At December 31, 2014, this credit facility had $35 million of outstanding borrowings.

Sunoco LP Credit Facility

In September 2014, Sunoco LP entered into a $1.25 billion revolving credit agreement (the "Sunoco LP Credit Facility"), which matures in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of December 31, 2014, the Sunoco LP Credit Facility had $683 million of outstanding borrowings.

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 assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

Covenants Related to Panhandle

Panhandle 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 Panhandle's lending agreements. Financial covenants exist in certain of Panhandle's debt agreements that require Panhandle 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 Panhandle 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 Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle'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 Panhandle's debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle 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 Panhandle's cash management program; and limitations on Panhandle'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

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fair value adjustments, to consolidated Adjusted EBITDA was 3.7 to 1 at December 31, 2014, as calculated in accordance with the credit agreements.

The West Texas Gulf Pipeline Company's $35 million credit facility limits West Texas Gulf, on a rolling four-quarter basis, to a minimum fixed charge coverage ratio of 1.00 to 1. 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 1.67 to 1 and 0.85 to 1, respectively, at December 31, 2014.

Covenants Related to Sunoco LP

The Sunoco LP Credit Facility requires Sunoco LP to maintain a leverage ratio of not more than 5.50 to 1. The maximum leverage ratio is subject to upwards adjustment of not more than 6.00 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in an acquisition of assets, equity interests, operating lines or divisions by Sunoco LP, a subsidiary, an unrestricted subsidiary or a joint venture for a purchase price of not less than $50 million. Indebtedness under the Sunoco LP Credit Facility is secured by a security interest in, among other things, all of the Sunoco LP's present and future personal property and all of the present and future personal property of its guarantors, the capital stock of its material subsidiaries (or 66% of the capital stock of material foreign subsidiaries), and any intercompany debt. Upon the first achievement by Sunoco LP of an investment grade credit rating, all security interests securing the Sunoco LP Credit Facility will be released.

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2014.

7. REDEEMABLE NONCONTROLLING INTERESTS:

The noncontrolling interest holders in one of Sunoco Logistics' consolidated subsidiaries have the option to sell their interests to Sunoco Logistics. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable interest on ETP's consolidated balance sheet as of December 31, 2014.

8. EQUITY:

Limited Partner interests are represented by Common, Class E Units, Class G Units and Class H Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. As of December 31, 2014, there were issued and outstanding 355.5 million Common Units representing an aggregate 99.3% Limited Partner interest in us. A total of 8.9 million Class E Units and 90.7 million Class G Units are outstanding and are reported as treasury units, which units are entitled to receive distributions in accordance with their terms. A total of 50.2 million Class H Units are also outstanding representing Limited Partner interests owned by ETE Holdings (see "Class H Units" below). No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash (as defined in our Partnership Agreement) from operating surplus after the minimum quarterly distribution has been paid. Please read "Quarterly Distributions of Available Cash" below. ETP GP, a wholly-owned subsidiary of ETE, owns all of the IDRs.

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Common Units

The change in Common Units was as follows:

	Years Ended December 31,		
	2014	2013	2012
Number of Common Units, beginning of period	333.8	301.5	225.5
Common Units issued in connection with the Susser Merger (see Note 3)	15.8	—	—
Common Units redeemed in connection with the Lake Charles LNG Transaction (see Note 3)	(18.7)	—	—
Common Units issued in connection with public offerings	—	13.8	15.5
Common Units issued in connection with certain acquisitions	—	49.5	57.4
Common Units redeemed for Class H Units	—	(50.2)	—
Common Units issued in connection with the Distribution Reinvestment Plan	2.8	2.3	1.0
Common Units issued in connection with Equity Distribution Agreements	21.4	16.9	1.6
Repurchases of Common Units in open-market transactions	—	(0.4)	—
Issuance of Common Units under equity incentive plans	0.4	0.4	0.5
Number of Common Units, end of period	355.5	333.8	301.5

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

Public Offerings

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

Date	Number of Common Units	Price per Unit	Net Proceeds
July 2012	15.5	$44.57	$671
April 2013	13.8	48.05	657

Proceeds from the offerings listed above were used to repay amounts outstanding under the ETP Credit Facility and/or to fund capital expenditures and capital contributions to joint ventures, and for general partnership purposes.

Equity Distribution Program

From time to time, we have sold Common Units through an equity distribution agreement. Such sales of Common Units are made by means of ordinary brokers’ transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent which is the counterparty to the equity distribution agreement.

In January 2013 and May 2013, we entered into equity distribution agreements pursuant to which we may sell from time to time Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the year ended December 31, 2014, we issued approximately 2.7 million units for $144 million, net of commissions of $2 million. No amounts of our Common Units remain available to be issued under our January 2013 and May 2013 equity distribution agreements.

In May 2014 and November 2014, we entered into equity distribution agreements pursuant to which we may sell from time to time Common Units having aggregate offering prices of up to $1.0 billion and $1.50 billion, respectively. During the year

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ended December 31, 2014, we issued approximately 18.8 million units for $1.08 billion, net of commissions of $11 million. As of December 31, 2014, approximately $1.41 billion of our Common Units remained available to be issued under our currently effective equity distribution agreements.

Equity Incentive Plan Activity

As discussed in Note 9, we issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Distribution Reinvestment Program

Our Distribution Reinvestment Plan (the "DRIP") provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units.

During the years ended December 31, 2014, 2013 and 2012, aggregate distributions of approximately $155 million, $109 million, and $43 million, respectively, were reinvested under the DRIP resulting in the issuance in aggregate of approximately 6.1 million Common Units.

As of December 31, 2014, a total of 7.3 million Common Units remain available to be issued under the existing registration statement.

Class E Units

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, with any excess thereof available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests. The Class E Units are treated as treasury units for accounting purposes because they are owned by a subsidiary of ETP Holdco, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the Class E Units at a future date. All of the 8.9 million Class E Units outstanding are held by a subsidiary and are reported as treasury units.

Class G Units

In conjunction with the Sunoco Merger, we amended our partnership agreement to create 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, Inc. 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 ETP 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.

Class H Units and Class I Units

Currently Outstanding

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 and (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.

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Pending Transaction

In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, ETP will also issue 100 Class I Units, as described below. In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016.

In connection with the transaction, ETP will also issue 100 Class I Units. The Class I Units will be generally entitled to: (i) pro rata allocations of gross income or gain until the aggregate amount of such items allocated to the holders of the Class I Units for the current taxable period and all previous taxable periods is equal to the cumulative amount of all distributions made to the holders of the Class I Units and (ii) after making cash distributions to Class H Units, any additional available cash deemed to be either operating surplus or capital surplus with respect to any quarter will be distributed to the Class I Units in an amount equal to the excess of the distribution amount set forth in our Partnership Agreement, as amended, (the "Partnership Agreement") for such quarter over the cumulative amount of available cash previously distributed commencing with the quarter ending March 31, 2015 until the quarter ending December 31, 2016. The impact of (i) the IDR subsidy adjustments and (ii) the Class I Unit distributions, along with the currently effective IDR subsidies, is included in the table below under "Quarterly Distributions of Available Cash" in the column titled "Pro Forma for Class H and Class I Units."

Sales of Common Units by Subsidiaries

With respect to our investments in Sunoco Logistics and Sunoco LP, we account for the difference between the carrying amount of our investment in and the underlying book value arising from the issuance or redemption of units by the respective subsidiary (excluding transactions with us) as capital transactions.

As a result of Sunoco Logistics' issuances of common units during the year ended December 31, 2014, we recognized increases in partners' capital of $113 million.

As a result of Sunoco LP's issuances of common units during the year ended December 31, 2014, we recognized increases in partners' capital of $62 million.

Sales of Common Units by Sunoco Logistics

In 2014, Sunoco Logistics entered into equity distribution agreements pursuant to which Sunoco Logistics may sell from time to time common units having aggregate offering prices of up to $1.25 billion. During the year ended ended December 31, 2014, Sunoco Logistics received proceeds of $477 million, net of commissions of $5 million, from the issuance of 10.3 million common units pursuant to the equity distribution agreement, which were used for general partnership purposes.

Additionally, Sunoco Logistics completed an overnight public offering of 7.7 million common units for net proceeds of $362 million in September 2014. The net proceeds from this offering were used to repay outstanding borrowings under the $1.50 billion Sunoco Logistics Credit Facility and for general partnership purposes.

Sales of Common Units by Sunoco LP

In October 2014 and November 2014, Sunoco LP issued an aggregate total of 9.1 million common units in an underwritten public offering. Aggregate net proceeds of $405 million from the offering were used to repay amounts outstanding under the $1.25 billion Sunoco LP Credit Facility and for general partnership purposes.

Quarterly Distributions of Available Cash

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

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

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 7, 2012	February 14, 2012	$0.8938
March 31, 2012	May 4, 2012	May 15, 2012	0.8938
June 30, 2012	August 6, 2012	August 14, 2012	0.8938
September 30, 2012	November 6, 2012	November 14, 2012	0.8938
December 31, 2012	February 7, 2013	February 14, 2013	0.8938
March 31, 2013	May 6, 2013	May 15, 2013	0.8938
June 30, 2013	August 5, 2013	August 14, 2013	0.8938
September 30, 2013	November 4, 2013	November 14, 2013	0.9050
December 31, 2013	February 7, 2014	February 14, 2014	0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550
September 30, 2014	November 3, 2014	November 14, 2014	0.9750
December 31, 2014	February 6, 2015	February 13, 2015	0.9950

In connection with transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods based on (i) the currently effective partnership agreement provisions, (ii) the assumed closing of the issuance of additional Class H Units and Class I Units, which is expected to occur in March 2015, and (iii) the assumed closing of the Regency Merger, which is expected to occur in the second quarter of 2015:

Years Ending December 31,	Currently Effective	Pro Forma for Class H and Class I Units[1]	Pro Forma for Regency Merger[2]
2015	$86	$31	$91
2016	107	77	142
2017	85	85	145
2018	80	80	140
2019	70	70	130
2020	35	35	50
2021	35	35	35
2022	35	35	35
2023	35	35	35
2024	18	18	18

(1) Pro forma amounts reflect the IDR subsidies, as adjusted for the pending issuance of additional Class H Units and Class I Units discussed above, as well as distributions on the Class I Units. The issuance of additional Class H Units and Class I Units is expected to close in March 2015.

(2) Pro forma amounts reflect the IDR subsidies, as adjusted for (i) the pending issuance of additional Class H Units and Class I Units (as described in Note (1) above) and (ii) the pending Regency Merger. Amounts reflected above assume that the Regency Merger is closed subsequent to the record date for the first quarter of 2015 distribution payment and prior to the record date for the second quarter 2015 distribution payment.

The amounts reflected above include the relinquishment of $350 million in the aggregate of incentive distributions that would potentially be made to ETE over the first forty fiscal quarters commencing immediately after the consummation of the Susser

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Merger. Such relinquishments would cease upon the agreement of an exchange of the Sunoco LP general partner interest and the incentive distribution rights between ETE and ETP.

Sunoco Logistics Quarterly Distributions of Available Cash

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$0.2725
March 31, 2013	May 9, 2013	May 15, 2013	0.2863
June 30, 2013	August 8, 2013	August 14, 2013	0.3000
September 30, 2013	November 8, 2013	November 14, 2013	0.3150
December 31, 2013	February 10, 2014	February 14, 2014	0.3312
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650
September 30, 2014	November 7, 2014	November 14, 2014	0.3825
December 31, 2014	February 9, 2015	February 13, 2015	0.4000

Sunoco Logistics Unit Split

On May 5, 2014, Sunoco Logistics' board of directors declared a two-for-one split of Sunoco Logistics common units. The unit split resulted in the issuance of one additional Sunoco Logistics common unit for every one unit owned as of the close of business on June 5, 2014. The unit split was effective June 12, 2014. All Sunoco Logistics unit and per unit information included in this report is presented on a post-split basis.

Sunoco LP Quarterly Distributions of Available Cash

Distributions declared by Sunoco LP subsequent to our acquisition on August 29, 2014 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2014	November 18, 2014	November 28, 2014	$0.5457
December 31, 2014	February 17, 2015	February 27, 2015	0.6000

Accumulated Other Comprehensive Income (Loss)

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

	December 31,	
	2014	2013
Available-for-sale securities	$3	$2
Foreign currency translation adjustment	(3)	(1)
Net loss on commodity related hedges	(1)	(4)
Actuarial gain (loss) related to pensions and other postretirement benefits	(57)	56
Investments in unconsolidated affiliates, net	2	8
Total AOCI, net of tax	$(56)	$61

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The tables below set forth the tax amounts included in the respective components of other comprehensive income (loss) for the periods presented:

	December 31,	
	2014	2013
Available-for-sale securities	$(1)	$(1)
Foreign currency translation adjustment	2	1
Actuarial gain relating to pension and other postretirement benefits	(37)	(39)
Total	$(36)	$(39)

9. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2014, an aggregate total of 5.4 million ETP Common Units remain available to be awarded under our equity incentive plans.

Restricted Units

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as "distribution equivalent rights." Under our equity incentive plans, our non-employee directors each receive grants with a five-year service vesting requirement.

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

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2013	3.2	$49.65
Awards granted	1.0	60.85
Awards vested	(0.5)	48.12
Awards forfeited	(0.1)	32.36
Unvested awards as of December 31, 2014	3.6	53.83

During the years ended December 31, 2014, 2013 and 2012, the weighted average grant-date fair value per unit award granted was $60.85, $50.54 and $43.93, respectively. The total fair value of awards vested was $26 million, $29 million and $29 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2014, a total of 3.6 million unit awards remain unvested, for which ETP expects to recognize a total of $128 million in compensation expense over a weighted average period of 2.0 years.

Cash Restricted Units. The Partnership has also granted cash restricted units, which vest 100% at the end of the third year of service. A cash restricted unit entitles the award recipient to receive cash equal to the market value of one ETP Common Unit upon vesting.

As of December 31, 2014, a total of 0.4 million unvested cash restricted units were outstanding.

Based on the trading price of ETP Common Units at December 31, 2014, the Partnership expects to recognize $24 million of unit-based compensation expense related to non-vested cash restricted units over a period of 1.8 years.

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Sunoco Logistics Unit-Based Compensation Plan

Sunoco Logistics' general partner has a long-term incentive plan for employees and directors, which permits the grant of restricted units and unit options of Sunoco Logistics covering an additional 0.7 million Sunoco Logistics common units. As of December 31, 2014, a total of 1.5 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $33 million of expense over a weighted average period of 2.9 years.

10. INCOME TAXES:

As a partnership, we are not subject to U.S. federal income tax and most state income taxes. However, the Partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) are summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
Current expense (benefit):			
Federal	$321	$51	$(3)
State	81	(2)	4
Total	402	49	1
Deferred expense (benefit):			
Federal	(50)	(6)	45
State	3	54	17
Total	(47)	48	62
Total income tax expense from continuing operations	$355	$97	$63

Historically, our effective rate differed from the statutory rate primarily due to Partnership earnings that are not subject to U.S. federal and most state income taxes at the Partnership level. The completion of the Southern Union Merger, Sunoco Merger, ETP Holdco Transaction and Susser Merger (see Note 3) significantly increased the activities conducted through corporate subsidiaries. A reconciliation of income tax expense (benefit) at the U.S. statutory rate to the income tax expense (benefit) attributable to continuing operations for the years ended December 31, 2014 and 2013 is as follows:

	December 31, 2014			December 31, 2013		
	Corporate Subsidiaries[1]	Partnership[2]	Consolidated	Corporate Subsidiaries[1]	Partnership[2]	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$217	$—	$217	$(166)	$—	$(166)
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	—	—	—	241	—	241
Nondeductible goodwill included in the Lake Charles LNG Transaction	105	—	105	—	—	—
State income taxes (net of federal income tax effects)	9	42	51	31	5	36
Premium on debt retirement	(10)	—	(10)	—	—	—
Foreign	(8)	—	(8)	—	—	—
Other	—	—	—	(13)	(1)	(14)
Income tax from continuing operations	$313	$42	$355	$93	$4	$97

[1] Includes ETP Holdco, Susser, Oasis Pipeline Company, Susser Petroleum Property Company LLC, Aloha Petroleum Ltd., Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. ETP

Holdco, which was formed via the Sunoco Merger and the ETP Holdco Transaction (see Note 3), includes Sunoco, Inc. and Panhandle. ETE held a 60% interest in ETP Holdco until April 30, 2013. Subsequent to the ETP Holdco Acquisition (see Note 3) on April 30, 2013, ETP owns 100% of ETP Holdco.

(2) Includes ETP and its subsidiaries that are classified as pass-through entities for federal income tax purposes.

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Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31,	
	2014	2013
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$116	$217
Pension and other postretirement benefits	47	57
Long term debt	53	108
Other	111	104
Total deferred income tax assets	327	486
Valuation allowance	(84)	(74)
Net deferred income tax assets	$243	$412
Deferred income tax liabilities:		
Properties, plants and equipment	$(1,486)	$(1,522)
Inventory	(153)	(302)
Investment in unconsolidated affiliates	(2,528)	(2,244)
Trademarks	(355)	(180)
Other	(32)	(45)
Total deferred income tax liabilities	(4,554)	(4,293)
Net deferred income tax liability	(4,311)	(3,881)
Less: current portion of deferred income tax liabilities, net	(85)	(119)
Accumulated deferred income taxes	$(4,226)	$(3,762)

The completion of the Southern Union Merger, Sunoco Merger, ETP Holdco Transaction and Susser Merger (see Note 3) significantly increased the deferred tax assets (liabilities). The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31,	
	2014	2013
Net deferred income tax liability, beginning of year	$(3,881)	$(3,606)
Susser acquisition	(488)	—
SUGS Contribution to Regency	—	(115)
Tax provision (including discontinued operations)	58	(111)
Other	—	(49)
Net deferred income tax liability	$(4,311)	$(3,881)

ETP Holdco, Susser and other corporate subsidiaries have gross federal net operating loss carryforwards of $5 million, all of which will expire in 2032 and 2033. Our corporate subsidiaries had less than $1 million of federal alternative minimum tax credits at December 31, 2014. Our corporate subsidiaries have state net operating loss carryforward benefits of $111 million, net of federal tax, which expire between 2014 and 2033. The valuation allowance of $84 million is applicable to the state net operating loss carryforward benefits applicable to Sunoco, Inc. pre-acquisition periods.

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The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2014	2013	2012
Balance at beginning of year	$429	$27	$2
Additions attributable to acquisitions	—	—	28
Additions attributable to tax positions taken in the current year	20	—	—
Additions attributable to tax positions taken in prior years	(1)	406	—
Settlements	(5)	—	—
Lapse of statute	(3)	(4)	(3)
Balance at end of year	$440	$429	$27

As of December 31, 2014, we have $439 million ($425 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate. We believe it is reasonably possible that its unrecognized tax benefits may be reduced by $4 million ($2 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco, Inc. has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco, Inc.'s 2004 through 2011 open statute years, Sunoco, Inc. has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco, Inc. is fully successful with its claims, it will receive tax refunds of approximately $372 million. However, due to the uncertainty surrounding the claims, a reserve of $372 million was established for the full amount of the claims. Due to the timing of the expected settlement of the claims and the related reserve, the receivable and the reserve for this issue have been netted in the financial statements as of December 31, 2014.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2014, we recognized interest and penalties of less than $1 million. At December 31, 2014, we have interest and penalties accrued of $6 million, net of tax.

In general, ETP and its subsidiaries are no longer subject to examination by the IRS for the 2010 and prior tax years. However, Sunoco, Inc. and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2007 and Southern Union and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2004. Sunoco, Inc. has been examined by the IRS for tax years through 2012. However, statutes remain open for tax years 2007 and forward due to carryback of net operating losses and/or claims regarding government incentive payments discussed above. All other issues are resolved. Though we believe the tax years are closed by statute, tax years 2004 through 2006 are impacted by the carryback of net operating losses and under certain circumstances may be impacted by adjustments for government incentive payments. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2014, the IRS has proposed only one adjustment for the years under examination. For the 2006 tax year, the IRS is challenging $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of its distribution operations and its gathering and processing operations. We have vigorously defended this tax position and believe we have reached a tentative settlement with the IRS which will not have a material impact on our consolidated financial position or results of operations.

ETP and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

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

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Certain FDOT/FTE projects have been or are the subject of litigation in Broward County, Florida. On November 16, 2012, FDOT paid to FGT the sum of approximately $100 million, representing the amount of the judgment, plus interest, in a case tried in 2011.

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On April 14, 2011, FGT filed suit against the FDOT/FTE and other defendants in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in FGT easements as part of FDOT/FTE's I-595 project. On August 21, 2013, FGT and FDOT/FTE entered into a settlement agreement pursuant to which, among other things, FDOT/FTE paid FGT approximately $19 million in September 2013 in settlement of FGT's claims with respect to the I-595 project. The settlement agreement also provided for agreed easement widths for FDOT/FTE right-of-way and for cost sharing between FGT and FDOT/FTE for any future relocations. Also in September 2013, FDOT/FTE paid FGT an additional approximate $1 million for costs related to the aforementioned turnpike/State Road 91 case tried in 2011.

FGT will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that FGT will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate FGT for its costs.

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP agreed to provide contingent, residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third party purchases.

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.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas and New Mexico. We commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992. Under the ICA, tariff rates must be just and reasonable and not unduly discriminatory and pipelines may not confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Transwestern Rate Case

On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to the 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in August 2015.

FGT Rate Case

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective May 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material

adverse effect on our financial position or results of operations.

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We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2058. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Years Ended December 31,		
	2014	2013	2012
Rental expense[1]	$139	$140	$57
Less: Sublease rental income	(26)	(24)	(4)
Rental expense, net	$113	$116	$53

(1) Includes contingent rentals totaling $24 million, $22 million and $6 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Future minimum lease commitments for such leases are:

Years Ending December 31:	
2015	$146
2016	124
2017	114
2018	105
2019	100
Thereafter	803
Future minimum lease commitments	1,392
Less: Sublease rental income	(34)
Net future minimum lease commitments	$1,358

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

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

MTBE Litigation

Sunoco, Inc., 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 also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2014, Sunoco, Inc. is a defendant in five cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, 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

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Rico action. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, Vermont, and Pennsylvania cases assert natural resource damage claims.

Fact discovery has concluded with respect to an initial set of 19 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, Inc. in these matters. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. 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.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise has filed a notice of appeal. In accordance with GAAP, no amounts related to the original verdict or the July 29, 2014 final judgment will be recorded in our financial statements until the appeal process is completed.

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2014 and 2013, accruals of approximately $37 million and $46 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued.

No amounts have been recorded in our December 31, 2014 or 2013 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Attorney General of the Commonwealth of Massachusetts v. New England Gas Company

On July 7, 2011, the Massachusetts Attorney General ("AG") filed a regulatory complaint with the Massachusetts Department of Public Utilities ("MDPU") against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling approximately $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, the Southern Union former Vice Chairman, President and Chief Operating Officer, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism

since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the

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applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Panhandle (as successor to Southern Union) believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Panhandle will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

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

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

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Currently operating Sunoco, Inc. retail sites.
- Legacy sites related to Sunoco, Inc., that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party ("PRP"). As of December 31, 2014, Sunoco, Inc. had been named as a PRP at approximately 51 identified or potentially identifiable "Superfund" sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.'s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated

balance sheets.

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The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	December 31,	
	2014	2013
Current	$39	$45
Non-current	352	350
Total environmental liabilities	$391	$395

In 2013, we 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.

During the years ended December 31, 2014 and 2013, Sunoco, Inc. had $46 million and $36 million, respectively, of expenditures related to environmental cleanup programs.

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

Our pipeline operations are subject to regulation by the U.S. Department of Transportation under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of the OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

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 OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot

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market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.

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

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby our subsidiaries generally 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 for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We may use derivatives in our liquids transportation and services segment to manage our storage facilities and the purchase and sale of purity NGLs.

Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are able and willing to bear it. Since the first quarter 2013, Sunoco Logistics has not designated any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

We also use derivatives to hedge a variety of price risks in our retail marketing segment. Futures and swaps are used to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales and transportation costs. The derivatives used in our retail marketing segment represent economic hedges; however, we have elected not to designate any of the hedges in this business segment. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment’s operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading and marketing activities related to power and natural gas in our all other segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to

our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

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The following table details our outstanding commodity-related derivatives:

	December 31, 2014		December 31, 2013	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	(232,500)	2015	9,457,500	2014-2019
Basis Swaps IFERC/NYMEX[(1)]	(13,907,500)	2015-2016	(487,500)	2014-2017
Swing Swaps	—	—	1,937,500	2014-2016
Options – Calls	5,000,000	2015	—	—
Power (Megawatt):				
Forwards	288,775	2015	351,050	2014
Futures	(156,000)	2015	(772,476)	2014
Options – Puts	(72,000)	2015	(52,800)	2014
Options – Calls	198,556	2015	103,200	2014
Crude (Bbls) – Futures	—	—	103,000	2014
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	57,500	2015	570,000	2014
Swing Swaps IFERC	46,150,000	2015	(9,690,000)	2014-2016
Fixed Swaps/Futures	(8,779,000)	2015-2016	(8,195,000)	2014-2015
Forward Physical Contracts	(9,116,777)	2015	5,668,559	2014-2015
Natural Gas Liquid (Bbls) – Forwards/Swaps	(2,179,400)	2015	(1,133,600)	2014
Refined Products (Bbls) – Futures	13,745,755	2015	(280,000)	2014
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(39,287,500)	2015	(7,352,500)	2014
Fixed Swaps/Futures	(39,287,500)	2015	(50,530,000)	2014
Hedged Item – Inventory	39,287,500	2015	50,530,000	2014
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	—	—	(1,825,000)	2014
Fixed Swaps/Futures	—	—	(12,775,000)	2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	—	—	(780,000)	2014
Crude (Bbls) – Futures	—	—	(30,000)	2014

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

Interest Rate Risk

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

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The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

Entity	Term	Type[1]	Notional Amount Outstanding December 31, 2014	Notional Amount Outstanding December 31, 2013
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	$—	$400
ETP	July 2015[2]	Forward-starting to pay a fixed rate of 3.38% and receive a floating rate	200	—
ETP	July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	—
ETP	July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	—
ETP	July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	—
ETP	July 2019[4]	Forward-starting to pay a fixed rate of 3.19% and receive a floating rate	300	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	—	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 1.73% and receive a fixed rate of 3.60%	200	400
Panhandle	November 2021	Pay a fixed rate of 3.82% and receive a floating rate	—	275

(1) Floating rates are based on 3-month LIBOR.

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

(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(4) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

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, gas and electric utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that 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.

We have maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded

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derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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.

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$43	$3	$—	$(18)
	43	3	—	(18)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	617	227	(577)	(209)
Commodity derivatives	23	39	(23)	(38)
Interest rate derivatives	3	47	(155)	(95)
	643	313	(755)	(342)
Total derivatives	$686	$316	$(755)	$(360)

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$23	$41	$(23)	$(38)
Broker cleared derivative contracts	Other current assets	674	265	(574)	(318)
		697	306	(597)	(356)
Offsetting agreements:					
Counterparty netting	Price risk management assets (liabilities)	(19)	(36)	19	36
Payments on margin deposit	Other current assets	5	(1)	(22)	55
		(14)	(37)	(3)	91
Net derivatives with offsetting agreements		683	269	(600)	(265)
Derivatives without offsetting agreements		3	47	(155)	(95)
Total derivatives		$686	$316	$(755)	$(360)

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

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

		Change in Value Recognized in OCI on Derivatives (Effective Portion) Years Ended December 31,		
		2014	2013	2012
Derivatives in cash flow hedging relationships:				
Commodity derivatives		$—	$(1)	$8
Total		$—	$(1)	$8

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,		
		2014	2013	2012
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$(3)	$4	$14
Total		$(3)	$4	$14

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness Years Ended December 31,		
		2014	2013	2012
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$(8)	$8	$54
Total		$(8)	$8	$54

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives Years Ended December 31,		
		2014	2013	2012
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$(6)	$(11)	$(7)
Commodity derivatives – Non-trading	Cost of products sold	106	(12)	(15)
Commodity contracts – Non-trading	Deferred gas purchases	—	(3)	(26)
Interest rate derivatives	Gains (losses) on interest rate derivatives	(157)	44	(4)
Total		$(57)	$18	$(52)

13. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees. Employer matching contributions are calculated using a formula based on employee contributions. We

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and our subsidiaries made matching contributions of $50 million, $38 million and $21 million to these 401(k) savings plans for the years ended December 31, 2014, 2013 and 2012, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Panhandle offered postretirement health care and life insurance plans that were available to substantially all of its employees, pending the retiree meeting certain age and service requirements.

Sunoco, Inc.

Sunoco, Inc. sponsors a defined benefit pension plan, which was frozen for most participants on June 30, 2010. On October 31, 2014, Sunoco, Inc. terminated the plan and anticipates approval for the distribution of assets from the plan, pending approval from the Pension Benefit Guaranty Corporation and the IRS, in the fourth quarter of 2015. Sunoco, Inc. also has a plan which provides health care benefits for substantially all of its current retirees. The cost to provide the postretirement benefit plan is shared by Sunoco, Inc. and its retirees. Access to postretirement medical benefits was phased out or eliminated for all employees retiring after July 1, 2010. In March, 2012, Sunoco, Inc. established a trust for its postretirement benefit liabilities. Sunoco made a tax-deductible contribution of approximately $200 million to the trust. The funding of the trust eliminated substantially all of Sunoco, Inc.’s future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

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Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2014			December 31, 2013		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Change in benefit obligation:						
Benefit obligation at beginning of period	$632	$61	$223	$1,117	$78	$296
Service cost	—	—	—	3	—	—
Interest cost	28	3	5	33	2	6
Amendments	—	—	1	—	—	2
Benefits paid, net	(45)	(9)	(28)	(99)	(16)	(26)
Actuarial (gain) loss and other	130	10	2	(74)	(3)	(14)
Settlements	(27)	—	—	(95)	—	—
Dispositions	—	—	(1)	(253)	—	(41)
Benefit obligation at end of period	718	65	202	632	61	223
Change in plan assets:						
Fair value of plan assets at beginning of period	600	—	284	906	—	312
Return on plan assets and other	70	—	6	43	—	17
Employer contributions	—	—	8	—	—	8
Benefits paid, net	(45)	—	(28)	(99)	—	(26)
Settlements	(27)	—	—	(95)	—	—
Dispositions	—	—	(5)	(155)	—	(27)
Fair value of plan assets at end of period	598	—	265	600	—	284
Amount underfunded (overfunded) at end of period	$120	$65	$(63)	$32	$61	$(61)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$—	$—	$90	$—	$—	$86
Current liabilities	—	(9)	(2)	—	(9)	(2)
Non-current liabilities	(120)	(56)	(25)	(32)	(52)	(23)
	$(120)	$(65)	$63	$(32)	$(61)	$61
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:						
Net actuarial gain	$18	$7	$(20)	$(86)	$(4)	$(25)

Prior service cost	—	—	17	—	—	18
	$18	$7	$(3)	$(86)	$(4)	$(7)

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The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2014			December 31, 2013		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$718	$65	N/A	$632	61	N/A
Accumulated benefit obligation	718	65	202	632	61	$223
Fair value of plan assets	598	—	265	600	—	284

Components of Net Periodic Benefit Cost

	December 31, 2014		December 31, 2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$—	$—	$3	$—
Interest cost	31	5	35	6
Expected return on plan assets	(40)	(8)	(54)	(9)
Prior service cost amortization	—	1	—	1
Actuarial loss amortization	(1)	(1)	2	—
Settlements	(4)	—	(2)	—
	(14)	(3)	(16)	(2)
Regulatory adjustment[1]	—	—	5	—
Net periodic benefit cost	$(14)	$(3)	$(11)	$(2)

(1) Southern Union, the predecessor of Panhandle, historically recovered certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers in its distribution operations. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2014		December 31, 2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.62%	2.24%	4.65%	2.33%
Rate of compensation increase	N/A	N/A	N/A	N/A

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The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2014		December 31, 2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65 %	3.02 %	3.50 %	2.68 %
Expected return on assets:				
Tax exempt accounts	7.50 %	7.00 %	7.50 %	6.95 %
Taxable accounts	N/A	4.50 %	N/A	4.42 %
Rate of compensation increase	N/A	N/A	N/A	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by Panhandle and Sunoco, Inc.'s other postretirement benefit plans are shown in the table below:

	December 31,	
	2014	2013
Health care cost trend rate	7.09 %	7.57 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.41 %	5.42 %
Year that the rate reaches the ultimate trend rate	2018	2018

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Panhandle plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its other postretirement plan asset portfolio, Panhandle has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of up to 10%.

The investment strategy of Sunoco, Inc. funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns and maintain a sufficient funded status of the plans. In anticipation of the pension plan termination, Sunoco, Inc. targeted the asset allocations to a more stable position by investing in growth assets and liability hedging assets.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

		Fair Value Measurements at December 31, 2014 Using Fair Value Hierarchy		
	Fair Value as of December 31, 2014	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$25	$25	$—	$—
Mutual funds[(1)]	110	—	110	—
Fixed income securities	463	—	463	—
Total	$598	$25	$573	$—

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(1) Primarily comprised of approximately 100% equities as of December 31, 2014.

		Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
	Fair Value as of December 31, 2013	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$12	$12	$—	$—
Mutual funds[1]	368	—	281	87
Fixed income securities	220	—	220	—
Total	$600	$12	$501	$87

(1) Primarily comprised of approximately 41% equities, 45% fixed income securities, and 14% in other investments as of December 31, 2013.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

		Fair Value Measurements at December 31, 2014 Using Fair Value Hierarchy		
	Fair Value as of December 31, 2014	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$9	$9	$—	$—
Mutual funds[1]	131	131	—	—
Fixed income securities	125	—	125	—
Total	$265	$140	$125	$—

(1) Primarily comprised of approximately 56% equities, 38% fixed income securities and 6% cash as of December 31, 2014.

		Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
	Fair Value as of December 31, 2013	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$10	$10	$—	$—
Mutual funds[1]	130	112	18	—
Fixed income securities	144	—	144	—
Total	$284	$122	$162	$—

(1) Primarily comprised of approximately 41% equities, 48% fixed income securities, 6% cash, and 5% in other investments as of December 31, 2013.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines. See Note 2 for information related to the framework used to measure the fair value of its pension and other postretirement plan assets.

Contributions

We expect to contribute approximately $129 million to pension plans and approximately $10 million to other postretirement plans in 2015. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

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Benefit Payments

Panhandle and Sunoco, Inc.'s estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

	Pension Benefits		
Years	Funded Plans	Unfunded Plans	Other Postretirement Benefits (Gross, Before Medicare Part D)
2015	$717	$9	$28
2016	—	8	26
2017	—	7	25
2018	—	7	23
2019	—	6	22
2020 – 2024	—	23	65

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Panhandle does not expect to receive any Medicare Part D subsidies in any future periods.

14. RELATED PARTY TRANSACTIONS:

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and on behalf of other subsidiaries of ETE, which includes the reimbursement of various operating and general and administrative expenses incurred by us on behalf of ETE and its subsidiaries.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles 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.

The Partnership also has related party transactions with several of its equity method investees. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets.

The following table summarizes the affiliate revenues on our consolidated statements of operations:

	Years Ended December 31,		
	2014	2013	2012
Affiliated revenues	$1,117	$1,550	$173

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

	December 31, 2014	2013
Accounts receivable from related companies:		
ETE	$11	$18
Regency	74	53
Dakota Access Pipeline	68	—
PES	6	7
FGT	9	29
ET Crude Oil	10	24
Lake Charles LNG	3	—
Other	29	34
Total accounts receivable from related companies:	$210	$165
Accounts payable to related companies:		
ETE	$—	$8
Regency	53	24
FGT	2	8
Lake Charles LNG	2	—
Other	5	5
Total accounts payable to related companies:	$62	$45

15. REPORTABLE SEGMENTS:

Our financial statements currently reflect the following reportable segments, which conduct their business in the United States, as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- liquids transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

Previously, our reportable segments included a separate segment for NGL transportation and services, which has now been combined into our liquids transportation and services segment and includes our operations related to NGL and crude, except for the crude transportation operations that are included in Sunoco Logistics. The liquids transportation and services segment includes the Bakken crude project, for which capital expenditures had previously been reported in the "All other" segment.

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.

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

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

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NGL sales and gathering, transportation and other fees. Revenues from our liquids transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our investment in Sunoco Logistics segment are primarily reflected in crude sales. Revenues from our retail marketing segment are primarily reflected in refined product sales.

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.

The following tables present financial information by segment:

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$2,652	$2,250	$2,012
Intersegment revenues	205	202	179
	2,857	2,452	2,191
Interstate transportation and storage:			
Revenues from external customers	1,057	1,270	1,109
Intersegment revenues	15	39	—
	1,072	1,309	1,109
Midstream:			
Revenues from external customers	1,210	1,307	1,757
Intersegment revenues	1,713	942	196
	2,923	2,249	1,953
Liquids transportation and services:			
Revenues from external customers	3,790	2,063	619
Intersegment revenues	121	64	31
	3,911	2,127	650
Investment in Sunoco Logistics:			
Revenues from external customers	17,920	16,480	3,109
Intersegment revenues	168	159	80
	18,088	16,639	3,189
Retail marketing:			
Revenues from external customers	22,484	21,004	5,926
Intersegment revenues	3	8	—
	22,487	21,012	5,926
All other:			
Revenues from external customers	2,045	1,965	1,170
Intersegment revenues	349	402	385
	2,394	2,367	1,555
Eliminations	(2,574)	(1,816)	(871)
Total revenues	$51,158	$46,339	$15,702

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	Years Ended December 31,		
	2014	2013	2012
Cost of products sold:			
Intrastate transportation and storage	$2,169	$1,737	$1,394
Midstream	2,174	1,579	1,273
Liquids transportation and services	3,166	1,655	361
Investment in Sunoco Logistics	17,110	15,574	2,885
Retail marketing	21,154	20,150	5,757
All other	2,338	2,309	1,496
Eliminations	(2,571)	(1,800)	(900)
Total cost of products sold	$45,540	$41,204	$12,266

	Years Ended December 31,		
	2014	2013	2012
Depreciation and amortization:			
Intrastate transportation and storage	$125	$122	$122
Interstate transportation and storage	203	244	209
Midstream	184	172	168
Liquids transportation and services	113	91	53
Investment in Sunoco Logistics	296	265	63
Retail marketing	189	114	28
All other	20	24	13
Total depreciation and amortization	$1,130	$1,032	$656

	Years Ended December 31,		
	2014	2013	2012
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$(1)	$—	$4
Interstate transportation and storage	151	142	120
Midstream	—	—	(9)
Liquids transportation and services	(3)	(2)	2
Investment in Sunoco Logistics	23	18	5
Retail marketing	2	2	1
All other	62	12	19
Total equity in earnings of unconsolidated affiliates	$234	$172	$142

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	Years Ended December 31,		
	2014	2013	2012
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$500	$464	$601
Interstate transportation and storage	1,110	1,269	1,013
Midstream	608	479	467
Liquids transportation and services	591	351	209
Investment in Sunoco Logistics	971	871	219
Retail marketing	731	325	109
All other	318	194	126
Total Segment Adjusted EBITDA	4,829	3,953	2,744
Depreciation and amortization	(1,130)	(1,032)	(656)
Interest expense, net of interest capitalized	(860)	(849)	(665)
Gain on deconsolidation of Propane Business	—	—	1,057
Gain on sale of AmeriGas common units	177	87	—
Goodwill impairment	—	(689)	—
Gains (losses) on interest rate derivatives	(157)	44	(4)
Non-cash unit-based compensation expense	(58)	(47)	(42)
Unrealized gains (losses) on commodity risk management activities	23	51	(9)
Inventory valuation adjustments	(473)	3	(75)
Loss on extinguishment of debt	—	—	(115)
Non-operating environmental remediation	—	(168)	—
Adjusted EBITDA related to discontinued operations	(27)	(76)	(99)
Adjusted EBITDA related to unconsolidated affiliates	(674)	(629)	(480)
Equity in earnings of unconsolidated affiliates	234	172	142
Other, net	(40)	12	22
Income from continuing operations before income tax expense	$1,844	$832	$1,820

	December 31,		
	2014	2013	2012
Assets:			
Intrastate transportation and storage	$4,563	$4,606	$4,691
Interstate transportation and storage	10,082	10,988	11,794
Midstream	3,548	3,133	4,946
Liquids transportation and services	4,581	4,326	3,765
Investment in Sunoco Logistics	13,619	11,650	10,291
Retail marketing	8,930	3,936	3,926
All other	2,898	5,063	3,817
Total assets	$48,221	$43,702	$43,230

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	Years Ended December 31,		
	2014	2013	2012
Additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate transportation and storage	$169	$47	$37
Interstate transportation and storage	411	152	133
Midstream	667	565	1,317
Liquids transportation and services	427	443	1,302
Investment in Sunoco Logistics	2,510	1,018	139
Retail marketing	259	176	58
All other	35	54	63
Total additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs	$4,478	$2,455	$3,049

	December 31,		
	2014	2013	2012
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$1	$1	$2
Interstate transportation and storage	1,954	2,040	2,142
Midstream	—	—	1
Liquids transportation and services	31	29	29
Investment in Sunoco Logistics	226	125	118
Retail marketing	19	22	21
All other	1,609	2,219	1,189
Total advances to and investments in unconsolidated affiliates	$3,840	$4,436	$3,502

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2014:					
Revenues	$12,232	$13,029	$13,618	$12,279	$51,158
Gross profit	1,366	1,393	1,494	1,365	5,618
Operating income	688	736	668	383	2,475
Net income	491	581	447	34	1,553
Common Unitholders' interest in net income (loss)	253	295	148	(90)	606
Basic net income (loss) per Common Unit	$0.76	$0.92	$0.44	$(0.28)	$1.77
Diluted net income (loss) per Common Unit	$0.76	$0.92	$0.44	$(0.28)	$1.77

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	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2013:					
Revenues	$10,854	$11,551	$11,902	$12,032	$46,339
Gross profit	1,260	1,322	1,248	1,305	5,135
Operating income (loss)	534	632	526	(151)	1,541
Net income (loss)	424	413	404	(473)	768
Common Unitholders' interest in net income (loss)	194	165	209	(666)	(98)
Basic net income (loss) per Common Unit	$0.63	$0.53	$0.55	$(1.90)	$(0.18)
Diluted net income (loss) per Common Unit	$0.63	$0.53	$0.55	$(1.90)	$(0.18)

The three months ended December 31, 2014 reflected the unfavorable impacts of $456 million related to non-cash inventory valuation adjustments primarily in our investment in Sunoco Logistics and retail marketing segments. The three months ended December 31, 2013 reflected ETP's recognition of a goodwill impairment of $689 million.

For the three months ended December 31, 2014 and 2013, distributions paid for the period exceeded net income attributable to partners by $544 million and $1.12 billion, respectively. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.