UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): August 12, 2015

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of Registrant as specified in its charter)

Delaware	**1-11727**	**73-1493906**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification Number)**

3738 Oak Lawn Avenue
Dallas, Texas 75219

(Address of principal executive offices)

(214) 981-0700

(Registrant’s telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

This Current Report on Form 8-K is being filed principally to reflect retrospective revisions that have been made to the consolidated financial statements of Energy Transfer Partners, L.P. (“ETP” or the “Partnership”) that were previously filed with the Securities and Exchange Commission by the Partnership on March 2, 2015 as Items 1, 6, 7 and 8 to its Annual Report on Form 10-K for the year ended December 31, 2014 (the “2014 Form 10-K”).

On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency Energy Partners LP (“Regency”), with Regency continuing as the surviving entity (the “Regency Merger”). Each Regency common unit and Class F unit was converted into the right to receive 0.4124 Partnership common units. ETP issued 172.2 million Partnership common units to Regency unitholders, including 15.5 million units issued to Partnership subsidiaries. The 1.9 million outstanding Regency series A preferred units were converted into corresponding new Partnership Series A Preferred Units on a one-for-one basis.

The Regency Merger was a combination of entities under common control; therefore Regency’s assets and liabilities were not adjusted. The Partnership’s consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date Energy Transfer Equity, L.P. acquired Regency’s general partner).

In order to preserve the nature and character of the disclosures set forth in the 2014 Form 10-K, the items included in this Form 8-K have been updated solely for matters relating specifically to the retrospective revision of ETP's financial statements and related information, except that subsequent events required to be reported under generally accepted accounting principles have been disclosed in the notes to the consolidated financial statements. This Form 8-K should be read in conjunction with the 2014 Form 10-K, and filings made by ETP with the SEC subsequent to the filing of the Form 10-K, including ETP's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015 filed on May 8, 2015 and ETP's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2015 filed on August 7, 2015.

Item 9.01 of this Current Report on Form 8-K revises certain information contained in ETP's 2014 Form 10-K to reflect certain retrospective revisions. In particular, Exhibit 99.1 contains a revised description of ETP’s business, financial statements and Management’s Discussion and Analysis of Financial Condition and Results of Operations.

Item 9.01 Financial Statements and Exhibits.

See the Exhibit Index set forth below for a list of exhibits included with this Form 8-K.

Exhibit Number	Description
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.
99.1	Revised Energy Transfer Partners, L.P. description of the business, financial statements as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.2	Report of Ernst & Young LLP on consolidated financial statements of Sunoco Logistics Partners L.P.
99.3	Report of Ernst & Young LLP on consolidated financials of Susser Holdings Corporation.
99.4	Report of Ernst & Young LLP on consolidated financials statements of Sunoco LP.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto 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

Date: August 12, 2015

/s/ Thomas E. Long

Thomas E. Long

Chief Financial Officer

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated August 12, 2015, with respect to the consolidated financial statements of Energy Transfer Partners, L.P. as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, included in this Current Report of Energy Transfer Partners, L.P. on Form 8-K. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Partners, L.P. on Forms S-3 (File No. 333-202507, File No. 333-199131, File No. 333-199130, and File No. 333-183388), on Form S-4 (File No. 333-161706), and on Forms S-8 (File No. 333-203823, File No. 333-200849, File No. 333-159878, and File No. 333-146338).

/s/ GRANT THORNTON LLP

Dallas, Texas
August 12, 2015

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement on Form S-3 No. 333-183388 of Energy Transfer Partners, L.P.
(2) Registration Statement on Form S-3 No. 333-199130 of Energy Transfer Partners, L.P.
(3) Registration Statement on Form S-3 No. 333-199131 of Energy Transfer Partners, L.P.
(4) Registration Statement on Form S-3 No. 333-202507 of Energy Transfer Partners, L.P.
(5) Registration Statement on Form S-4 No. 333-161706 of Energy Transfer Partners, L.P.
(6) Registration Statement on Form S-8 No. 333-146338 of Energy Transfer Partners, L.P.
(7) Registration Statement on Form S-8 No. 333-159878 of Energy Transfer Partners, L.P.
(8) Registration Statement on Form S-8 No. 333-200849 of Energy Transfer Partners, L.P.
(9) Registration Statement on Form S-8 No. 333-203823 of Energy Transfer Partners, L.P.

of our report dated March 1, 2013, with respect to the consolidated statements of comprehensive income, equity and cash flows of Sunoco Logistics Partners L.P., included in this Current Report (Form 8-K) of Energy Transfer Partners, L.P. which includes the adjusted consolidated financial statements of Energy Transfer Partners, L.P. for the consolidation of an entity under common control.

/s/Ernst & Young LLP

Philadelphia, Pennsylvania
August 12, 2015

Exhibit 23.3

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement on Form S-3 No. 333-183388 of Energy Transfer Partners, L.P.
(2) Registration Statement on Form S-3 No. 333-199130 of Energy Transfer Partners, L.P.
(3) Registration Statement on Form S-3 No. 333-199131 of Energy Transfer Partners, L.P.
(4) Registration Statement on Form S-3 No. 333-202507 of Energy Transfer Partners, L.P.
(5) Registration Statement on Form S-4 No. 333-161706 of Energy Transfer Partners, L.P.
(6) Registration Statement on Form S-8 No. 333-146338 of Energy Transfer Partners, L.P.
(7) Registration Statement on Form S-8 No. 333-159878 of Energy Transfer Partners, L.P.
(8) Registration Statement on Form S-8 No. 333-200849 of Energy Transfer Partners, L.P.
(9) Registration Statement on Form S-8 No. 333-203823 of Energy Transfer Partners, L.P.

of our report dated February 28, 2015, (except for Note 2, as to which the date is April 30, 2015), with respect to the consolidated financial statements of Susser Holdings Corporation (not presented separately herein), included in this Current Report on Form 8-K of Energy Transfer Partners, L.P.

/s/Ernst & Young LLP

Houston, Texas
August 10, 2015

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement on Form S-3 No. 333-183388 of Energy Transfer Partners, L.P.
(2) Registration Statement on Form S-3 No. 333-199130 of Energy Transfer Partners, L.P.
(3) Registration Statement on Form S-3 No. 333-199131 of Energy Transfer Partners, L.P.
(4) Registration Statement on Form S-3 No. 333-202507 of Energy Transfer Partners, L.P.
(5) Registration Statement on Form S-4 No. 333-161706 of Energy Transfer Partners, L.P.
(6) Registration Statement on Form S-8 No. 333-146338 of Energy Transfer Partners, L.P.
(7) Registration Statement on Form S-8 No. 333-159878 of Energy Transfer Partners, L.P.
(8) Registration Statement on Form S-8 No. 333-200849 of Energy Transfer Partners, L.P.
(9) Registration Statement on Form S-8 No. 333-203823 of Energy Transfer Partners, L.P.

of our report dated February 27, 2015, with respect to the consolidated financial statements of Sunoco LP (not presented separately herein), included in this Current Report on Form 8-K of Energy Transfer Partners, L.P.

/s/Ernst & Young LLP

Houston, Texas
August 10, 2015

TABLE OF CONTENTS

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," "forecast," "may," "will" or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from those anticipated, projected 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
Aqua – PVR	Aqua – PVR Water Services, LLC
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Aqua – PVR	Aqua – PVR Water Services, LLC
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
Coal Handling	Coal Handling Solutions LLC, Kingsport Handling LLC, and Kingsport Services LLC, now known as Materials Handling Solutions LLC
CrossCountry	CrossCountry Energy, LLC
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
Eagle Rock	Eagle Rock Energy Partners, L.P.
ELG	Edwards Lime Gathering LLC
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
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
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of Regency
HPC	RIGS Haynesville Partnership Co.
HOLP	Heritage Operating, L.P.
Hoover Energy	Hoover Energy Partners, LP
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
MEP	Midcontinent Express Pipeline LLC
MGE	Missouri Gas Energy
Mi Vida JV	Mi Vida JV LLC
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

ORS	Ohio River System LLC
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
PVR	PVR Partners, L.P.
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, a joint venture between subsidiaries of ETC OLP and Sunoco, Inc.
RIGS	Regency Intrastate Gas System
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
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 GP	Sunoco GP LLC, the general partner of Sunoco LP
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.

PART I

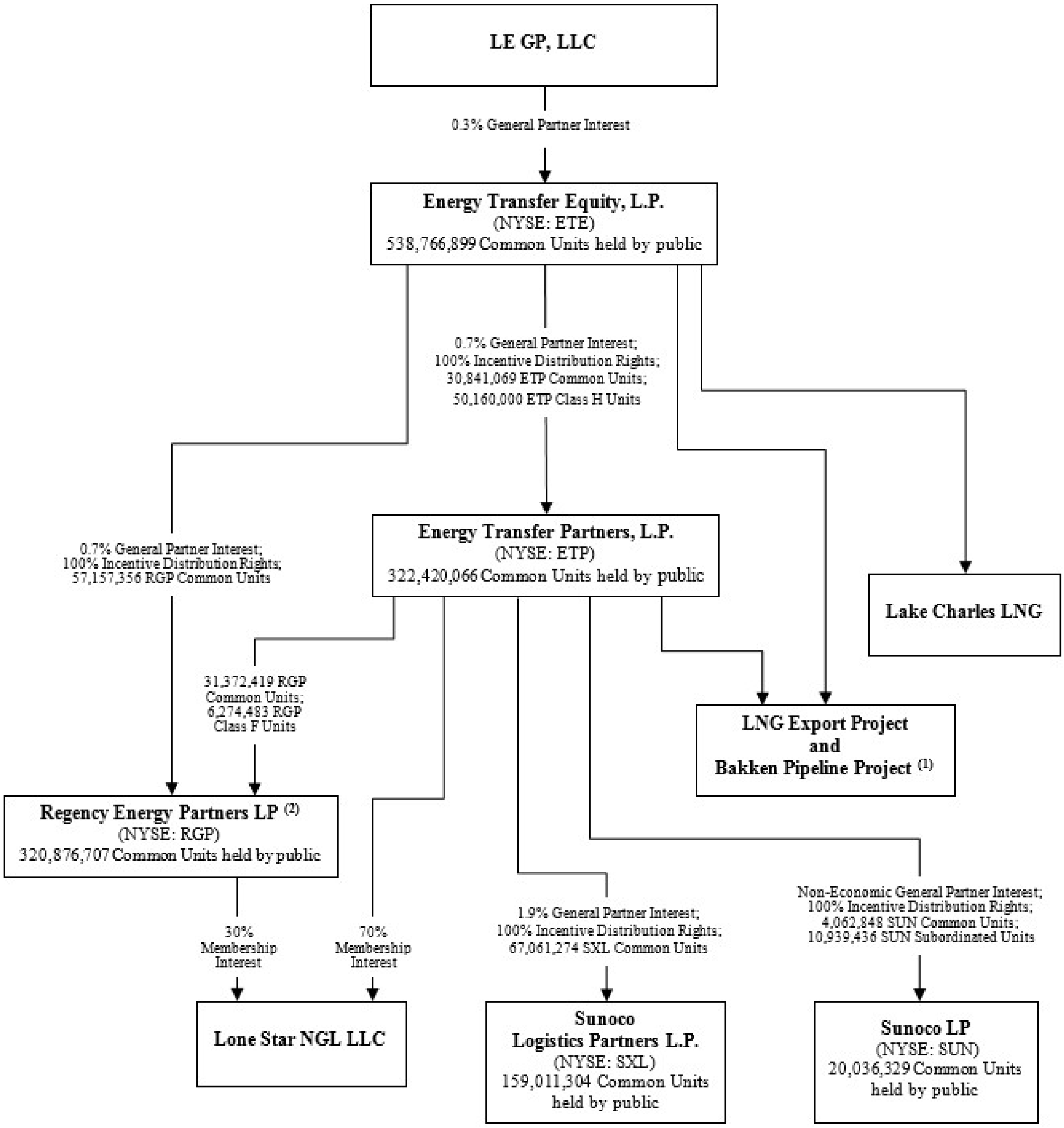
ITEM 1. BUSINESS

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.

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 closed in March 2015.

(2) As discussed below, in April 2015, ETP and Regency completed their previously announced merger.

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

Significant Achievements in 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 April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the “Regency Merger”). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.
- In March 2015, ETP and ETE completed the previously announced transaction, whereby ETE transferred 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.
- 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.
- 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 16 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.

Through Regency, we own a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets.

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 50% interests in the joint ventures that own the 185-mile Fayetteville Express pipeline and the 500-mile Midcontinent 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.

Regency owns a 50% interest in the MEP pipeline system, operated by KMI, and has the capability to transport up to 1.8 Bcf/d of natural gas, and the pipeline capacity is nearly fully subscribed, Zone 1 is 95% subscribed and Zone 2 is fully subscribed, with long-term binding commitments from creditworthy shippers. Results of MEP's operations are determined primarily by the volumes of natural gas transported and subscribed on its interstate pipeline system and the level of fees charged to customers. MEP generates revenues and margins principally under fee-based transportation contracts. The margin MEP earns is primarily related to fixed capacity reservation charges that are not directly dependent on throughput volumes or commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, MEP's revenues would not be significantly impacted until expiration of the current contracts.

Gulf States is a small interstate pipeline that uses cost-based rates and terms and conditions of service for shippers wishing to secure capacity for interstate transportation service. Rates charged are largely governed by long-term negotiated rate agreements.

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

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

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 32,900 miles of in service natural gas and NGL gathering pipelines with approximately 5.7 Bcf/d of gathering capacity, 21 natural gas processing plants, 27 natural gas treating facilities and 4 natural gas conditioning facilities with an aggregate processing, treating and conditioning capacity of approximately 9.4 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 also includes Regency's 60% interest in ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in south Texas, Regency's 33.33% membership interest in Ranch Westex JV LLC, which processes natural gas delivered from the NGLs-rich shale formations in west Texas, Regency's 50% interest in Sweeny Gathering LP, which operates a natural gas gathering facility in south Texas, Regency's 51% membership interest in Aqua – PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, Regency's 75% membership interest in ORS, which will operate a natural gas gathering system in the Utica shale in Ohio, and Regency's 50% interest in Mi Vida JV, which will operate a cryogenic processing plant and related facilities in west Texas.

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 own 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 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.

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:

- 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.
- Through Regency, we own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. Through Regency, we also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.

- Through Regency, we are involved in the management of coal and natural resources properties and the related collection of royalties. Through Regency, we also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also included Regency's 50% interesting in Coal Handling, which owns and operates end-user coal handling facilities. Regency purchased the remaining 50% interest in Coal Handling effective December 31, 2014.

Asset Overview

Intrastate Transportation and Storage

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

ET Fuel System

- Capacity of 5.2 Bcf/d
- Approximately 2,870 miles of natural gas pipeline
- Two storage facilities with 12.4 Bcf of total working gas capacity
- Bi-directional capabilities

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

The ET Fuel System also includes our Bethel natural gas storage facility, with a working capacity of 6.4 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. All of our storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 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.

RIGS Haynesville Partnership Co.

- Capacity of 2.1 Bcf/d
- Approximately 450 miles of natural gas pipeline
- Regency owns a 49.99% general partner interest

RIGS is a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets.

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.

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.

Midcontinent Express Pipeline LLC

- Capacity of 1.8 Bcf/d
- Approximately 500 miles of interstate natural gas pipeline
- Regency owns a 50% interest

MEP owns a 500-mile interstate pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipeline System in Butler, Alabama.

Gulf States

- Capacity of 140,000 MMBtu/d
- Approximately 10 miles of interstate natural gas pipeline

Gulf States owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

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.

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.

Regency Arklatex System

- Approximately 2,800 miles of natural gas pipeline
- Four cryogenic natural gas processing facilities, two refrigeration plants, a conditioning plant and two amine treating plants

Regency's Arklatex assets gather, compress, treat and dehydrate natural gas in several Parishes of north and west Louisiana and several counties in east Texas. These assets also include cryogenic natural gas processing facilities, a refrigeration plant, a conditioning plant, amine treating plants, and an interstate NGL pipeline.

Through the gathering and processing systems described above and their interconnections with RIGS in north Louisiana, Regency offers producers wellhead-to-market services, including natural gas gathering, compression, processing, treating and transportation.

In May 2014, Regency announced the construction of a new 200 MMcf/d cryogenic processing plant and 47-mile, 40,000 bbls/d capacity NGL pipeline, for a combined total of $191 million, which is expected to be completed in mid-2015.

Regency South Texas System

- Approximately 1,700 miles of natural gas pipeline
- Three treating plants

Regency's south Texas assets gather, compress, treat and dehydrate natural gas in Bee, LaSalle, Webb, Karnes, Atascosa, McMullen, Frio and Dimmitt counties. The pipeline systems are connected to third-party processing plants and Regency's treating facilities that include acid gas reinjection wells located in McMullen County, Texas. Regency also gathers oil for producers in the region and delivers it to tanks for further transportation by truck or pipeline.

The natural gas supply for Regency's south Texas gathering systems is derived from a combination of natural gas wells located in a mature basin that generally have long lives and predictable gas flow rates, including the Frio, Vicksburg, Miocene, Canyon Sands and Wilcox formations, and the NGLs-rich and oil-rich Eagle Ford shale formation.

Regency owns a 60% interest in ELG with Talisman Energy USA Inc. and Statoil Texas Onshore Properties LP owning the remaining 40% interest. Regency operates a natural gas gathering oil pipeline and oil stabilization facilities for the joint venture while its joint venture partners operate a lean gas gathering system in the Edwards Lime natural gas trend that delivers to this system.

Regency Permian System

- Approximately 7,820 miles of natural gas pipeline
- Six processing and treating plants, two processing plants and two treating plants

Regency's Permian Basin gathering system assets offer wellhead-to-market services to producers in the Texas counties of Ward, Winkler, Reeves, Pecos, Crocket, Upton, Crane, Ector, Culberson, Reagan and Andrews counties, as well as into Eddy and Lea counties in New Mexico which surround the Waha Hub, one of Texas's developing NGLs-rich natural gas market areas. As a result of the proximity of Regency's system to the Waha Hub, the Waha gathering system has a variety of market outlets for the natural gas that Regency gathers and processes, including several major interstate and intrastate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets. The NGL market outlets include Lone Star's NGL pipeline.

In October 2014, Regency entered into a joint venture with Anadarko Mi Vida LLC ("Anadarko"). Anadarko and Regency each own a 50% membership interest in the new joint venture, Mi Vida JV. Regency will construct and operate a 200 MMcf/d cryogenic processing plant and related facilities in west Texas, on behalf of Mi Vida JV.

Regency owns a 33.33% membership interest in Ranch JV which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The joint venture owns a 25 MMcf/d refrigeration plant and a 100 MMcf/d cryogenic processing plant.

Regency Mid-Continent Region

- Approximately 13,000 miles of natural gas pipeline
- 14 processing facilities

Regency's mid-continent systems are located in two large natural gas producing regions in the United States, the Hugoton Basin in southwest Kansas, and the Anadarko Basin in western Oklahoma and the Texas Panhandle. These mature basins have continued to provide generally long-lived, predictable production volume. Regency's mid-continent gathering assets are extensive systems that gather, compress and dehydrate low-pressure gas. Regency has 14 natural gas producing facilities and approximately 12,995 miles of gathering pipeline.

Regency operates its mid-continent gathering systems at low pressures to maximize the total throughput volumes from the connected wells. Wellhead pressures are therefore adequate to allow for flow of natural gas into the gathering lines without the cost of wellhead compression.

Regency also owns the Hugoton gathering system that has 1,900 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

Regency Eastern Region

- Approximately 370 miles of natural gas pipeline

Regency's eastern region assets are located in Pennsylvania, Ohio, and West Virginia, and gather natural gas from the Marcellus and Utica basins. Regency's eastern gathering assets include approximately 370 miles of natural gas gathering pipeline, natural gas trunkline pipelines, and fresh water pipelines, and the Lycoming, Wyoming, East Lycoming, Bradford, Green County, and Preston gathering and processing systems.

Regency also own a 51% membership interest in Aqua – PVR, a joint venture that transports and supplies fresh water to natural gas producers drilling in the Marcellus Shale in Pennsylvania.

In August 2014, Regency entered into a joint venture with American Energy – Midstream, LLC ("AEM"). Regency and AEM own a 75% and 25% membership interest, respectively, in the new joint venture ORS. On behalf of ORS, Regency is constructing and will operate its Ohio Utica River System, (the "ORS System") which consists of a 52-mile, 36-inch gathering trunkline that will be capable of delivering up to 2.1 bcf/d to Rockies Express Pipeline ("REX") and Texas Eastern Transmission, and potentially others and the construction of 25,000 horsepower of compression at the REX interconnect. This project will also include the construction of a 12-mile, 30-inch lateral that will initially connect to the tailgate of the Cadiz processing plant and Harrison County wellhead production. The system is expected to be completed in the third quarter of 2015. Total costs for the ORS System are expected to be approximately $500 million; 75% contributed from Regency and 25% contributed from AEM. Additionally, Regency and American Energy - Utica, LLC ("AEU"), an affiliate of AEM, entered into a gathering agreement for gas produced from the Utica Shale in eastern Ohio by AEU.

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.

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.

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 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.

The following table outlines the number of Sunoco Logistics' active terminals and storage capacity by state at December 31, 2014:

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.

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.

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 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 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.

Contract Services Operations

Regency owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. Regency's contract treating services are primarily located in Texas, Louisiana and Arkansas.

Natural Resources Operations

Regency's Natural Resources operations primarily involve the management and leasing of coal properties and the subsequent collection of royalties. Regency also earns revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage fees. As of December 31, 2014, Regency owned or controlled approximately 821 million tons of proven and probable coal reserves in central and northern Appalachia, properties in eastern Kentucky, Tennessee, southwestern Virginia and southern West Virginia; and the Illinois Basin, properties in southern Illinois, Indiana, and western Kentucky and as the operator of end-user coal handling facilities. Since 2004, the Natural Resources segment held a 50% interest in a coal services company with Alpha Natural Resources. In December 2014, we acquired the remaining 50% membership interest. The company, now know as Materials Handling Solutions, LLC, owns and operates facilities for industrial customers on a fee basis. During 2014, our coal reserves located in the San Juan basin depleted and our associated coal royalties revenues ceased.

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.

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 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, Sea Robin and Gulf States pipelines transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain storage facilities that are subject to the FERC's regulatory oversight.

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

- the certification and construction of new facilities;
- the review and approval of transportation rates;
- the types of services that our regulated assets are permitted to perform;
- the terms and conditions associated with these services;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities; and
- the initiation and discontinuation of services.

Under the NGA, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The maximum rates to be charged by NGA-jurisdictional natural gas companies and their terms and conditions for service are generally required to be on file with the FERC in FERC-approved tariffs. Most natural gas companies are authorized to offer discounts from their FERC-approved maximum just and reasonable rates when competition warrants such discounts. Natural gas companies are also generally permitted to offer negotiated rates different from rates established in their tariff if, among other requirements, such companies' tariffs offer a cost-based recourse rate available to a prospective shipper as an alternative to the negotiated rate. Natural gas companies must make offers of rate discounts and negotiated rates on a basis that is not unduly discriminatory. Existing tariff rates may be challenged by complaint, and if found unjust and unreasonable, may be altered on a prospective basis by the FERC. We cannot guarantee that the FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities.

In 2011, in lieu of filing a new NGA Section 4 general rate case, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. In general, the settlement provides for the continued use of Transwestern's currently effective transportation and fuel tariff rates, with the exception of certain San Juan Lateral fuel rates, which we were required to reduce over a three year period beginning in April 2012. The settlement also resolves certain non-rate matters, and approves Transwestern's use of certain previously approved accounting methodologies. 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.

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 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 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 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 $401 million and $403 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 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, 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 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.

As of December 31, 2014, Regency employed 1,879 employees. None of these employees are represented by a labor union and there are no outstanding collective bargaining agreements to which Regency is a party. Regency believes that it’s relations with its 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.

PART II

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, and the Regency Merger as reorganizations 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) and the retrospective consolidation of Regency into ETP beginning May 26, 2010 (the date ETE obtained control of Regency).

The ETP Holdco Transaction only impacted interim periods in 2012, and no prior annual amounts have been adjusted for the ETP Holdco Transaction. The Regency Merger impacted each of the years ended December 31, 2014, 2013, 2012, 2011 and 2010.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
Statement of Operations Data:					
Total revenues	$ 55,475	$ 48,335	$ 16,964	$ 8,190	$ 6,556
Operating income	2,443	1,619	1,425	1,279	1,078
Income from continuing operations	1,235	713	1,754	740	616
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	62,674	49,900	48,394	20,443	16,915
Long-term debt, less current maturities	24,973	19,761	17,599	9,075	7,546
Total equity	25,311	18,694	19,982	9,247	8,035
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	444	391	347	156	106
Growth (accrual basis)	5,050	2,936	3,186	1,757	1,430
Cash paid for acquisitions	2,367	1,737	1,364	1,972	370

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 Regency; and
  - interstate natural gas transportation and storage through ET Interstate, Panhandle and Regency. 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. Regency is the parent company of Gulf States and owns a 50% interest in MEP.
- 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 April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.

In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will 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.

Bakken Pipeline Transaction

In March 2015, ETE transferred 30.8 million Partnership common units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership 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. In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to the Partnership. These IDR subsidies, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

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) owns 35% of Rover and ETP owns 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.

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 9 to our consolidated financial statements.

General

Our primary objective is to increase the level of our distributable cash flow to our unitholders 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.

  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, Panhandle, MEP and Gulf States 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 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. With the completion of our 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 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, and the Regency Merger as reorganizations of entities under common control. Accordingly, ETP's consolidated financial statements reflect the retrospective consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union) and the retrospective consolidation of Regency into ETP beginning May 26, 2010 (the date ETE obtained control of Regency).

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	$ 559	$ 521	$ 38
Interstate transportation and storage	1,212	1,368	(156)
Midstream	1,349	766	583
Liquids transportation and services	591	350	241
Investment in Sunoco Logistics	971	871	100
Retail marketing	731	325	406
All other	297	203	94
Total	5,710	4,404	1,306
Depreciation, depletion and amortization	(1,669)	(1,296)	(373)
Interest expense, net of interest capitalized	(1,165)	(1,013)	(152)
Gain on sale of AmeriGas common units	177	87	90
Goodwill impairment	(370)	(689)	319
Gains (losses) on interest rate derivatives	(157)	44	(201)
Non-cash unit-based compensation expense	(68)	(54)	(14)
Unrealized gains on commodity risk management activities	112	42	70
Inventory valuation adjustments	(473)	3	(476)
Loss on extinguishment of debt	(25)	(7)	(18)
Non-operating environmental remediation	—	(168)	168
Adjusted EBITDA related to discontinued operations	(27)	(76)	49
Adjusted EBITDA related to unconsolidated affiliates	(748)	(722)	(26)
Equity in earnings of unconsolidated affiliates	332	236	96
Other, net	(36)	19	(55)
Income from continuing operations before income tax expense	1,593	810	783
Income tax expense from continuing operations	(358)	(97)	(261)
Income from continuing operations	1,235	713	522
Income from discontinued operations	64	33	31
Net income	$ 1,299	$ 746	$ 553

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions, including Regency's acquisitions in 2014, partially offset by a decrease in depreciation and amortization of $39 million related to the Lake Charles LNG Transaction.

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 2014, a $370 million goodwill impairment was recorded related to Regency's Permian Basin gathering and processing operations. The decline in estimated fair value of that reporting unit was primarily driven by a significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses. An assessment of these factors in the fourth quarter of 2014 led to a conclusion that the estimated fair value of Regency's Permian reporting unit was less than its carrying amount.

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.

Loss on Debt Extinguishment. For the years ended December 31, 2014 and 2013, losses on debt extinguishments were related to Regency's repurchase of its senior notes during the respective periods.

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.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2014	Years Ended December 31, 2013	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 96	$ 87	$ 9
FEP	55	55	—
PES	59	(48)	107
MEP	45	40	5
HPC	28	30	(2)
AmeriGas	21	50	(29)
Other	28	22	6
Total equity in earnings of unconsolidated affiliates	$ 332	$ 236	$ 96
Adjusted EBITDA related to unconsolidated affiliates[1]:			
Citrus	$ 305	$ 296	$ 9
FEP	75	75	—
PES	86	(30)	116
MEP	102	100	2
HPC	53	51	2
AmeriGas	56	175	(119)
Other	71	55	16
Total Adjusted EBITDA related to unconsolidated affiliates	$ 748	$ 722	$ 26
Distributions received from unconsolidated affiliates:			
Citrus	$ 168	$ 175	$ (7)
FEP	70	69	1
PES	—	65	(65)
MEP	73	72	1
HPC	48	238	(190)
AmeriGas	22	86	(64)
Other	40	27	13
Total distributions received from unconsolidated affiliates	$ 421	$ 732	$ (311)

(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 Coal Handling 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.

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 16 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	57	57	—
Segment Adjusted EBITDA	$ 559	$ 521	$ 38

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 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	Years Ended December 31, 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.

Interstate Transportation and Storage

	Years Ended December 31, 2014	Years Ended December 31, 2013	Change
Natural gas transported (MMBtu/d)	6,159,546	6,417,529	(257,983)
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	482	471	11
Other	11	—	11
Segment Adjusted EBITDA	$ 1,212	$ 1,368	$ (156)

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.

Midstream

	Years Ended December 31,		
	2014	2013	Change
Gathered volumes (MMBtu/d)	7,780,278	4,609,359	3,170,919
NGLs produced (Bbls/d)	317,487	198,894	118,593
Equity NGLs (Bbls/d)	27,611	19,340	8,271
Revenues	$ 6,823	$ 4,276	$ 2,547
Cost of products sold	4,893	3,130	1,763
Gross margin	1,930	1,146	784
Unrealized gains on commodity risk management activities	(89)	2	(91)
Operating expenses, excluding non-cash compensation expense	(481)	(358)	(123)
Selling, general and administrative expenses, excluding non-cash compensation expense	(23)	(29)	6
Adjusted EBITDA related to unconsolidated affiliates	12	3	9
Other	—	2	(2)
Segment Adjusted EBITDA	$ 1,349	$ 766	$ 583

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. Midstream gross margin increased for the year ended December 31, 2014 compared to the prior year due to an increase of $669 million related to Regency’s gathering and processing operations, primarily due to Regency’s acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014, and an increase in fee-based revenues of $121 million from ETP’s legacy midstream assets due to increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale.

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 a $76 million increase in pipeline and plant maintenance and materials due to organic growth on Regency’s assets in south and west Texas, as well as Regency’s acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014. The remainder of the increase was primarily due to increased employee-related costs from Regency’s acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014.

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 throughput and condensate sales related to Regency’s investment in Ranch JV.

Liquids Transportation and Services

	Years Ended December 31, 2014	Years Ended December 31, 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	$ 2,126	$ 1,785
Cost of products sold	3,166	1,654	1,512
Gross margin	745	472	273
Unrealized gains on commodity risk management activities	(12)	(1)	(11)
Operating expenses, excluding non-cash compensation expense	(128)	(110)	(18)
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	$ 350	$ 241

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	Years Ended December 31, 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.

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.

Retail Marketing

	Years Ended December 31, 2014	Years Ended December 31, 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.

All Other

	Years Ended December 31, 2014	2013	Change
Revenue	$ 3,331	$ 2,597	$ 734
Cost of products sold	2,975	2,337	638
Gross margin	356	260	96
Unrealized gains on commodity risk management activities	(14)	(2)	(12)
Operating expenses, excluding non-cash compensation expense	(106)	(104)	(2)
Selling, general and administrative expenses, excluding non-cash compensation expense	(177)	(148)	(29)
Adjusted EBITDA related to discontinued operations	27	76	(49)
Adjusted EBITDA related to unconsolidated affiliates	146	147	(1)
Other	73	(2)	75
Elimination	(8)	(24)	16
Segment Adjusted EBITDA	$ 297	$ 203	$ 94

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;
- Regency's investment in Coal Handling, an entity that owns and operates end-user coal handling facilities; 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;
- an increase of $50 million in gross margin related to Regency's contract service operations due to increased revenue generating horsepower and $58 million related to Regency's natural resources operations due to the acquisition of those assets in March 2014, offset by an increase of $26 million in operating expenses;
- 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 and recent acquisitions from our natural gas marketing business of $15 million and $6 million, respectively;
- higher earnings from our investment in PES of $116 million, 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 2014 and 2013;
- 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
- an increase of $78 million in selling, general and administrative expenses related to Regency's operations, primarily due to a $33 million increase in acquisition costs, with the remainder primarily attributable to increased employee-related expenses;
- 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.

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	$ 521	$ 667	$ (146)
Interstate transportation and storage	1,368	1,117	251
Midstream	766	613	153
Liquids transportation and services	350	209	141
Investment in Sunoco Logistics	871	219	652
Retail marketing	325	109	216
All other	203	205	(2)
Total	4,404	3,139	1,265
Depreciation and amortization	(1,296)	(858)	(438)
Interest expense, net of interest capitalized	(1,013)	(788)	(225)
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	(54)	(47)	(7)
Unrealized gains on commodity risk management activities	42	2	40
Inventory valuation adjustments	3	(75)	78
Loss on extinguishment of debt	(7)	(124)	117
Non-operating environmental remediation	(168)	—	(168)
Adjusted EBITDA related to discontinued operations	(76)	(99)	23
Adjusted EBITDA related to unconsolidated affiliates	(722)	(646)	(76)
Equity in earnings of unconsolidated affiliates	236	212	24
Other, net	19	48	(29)
Income from continuing operations before income tax expense	810	1,817	(1,007)
Income tax expense from continuing operations	(97)	(63)	(34)
Income from continuing operations	713	1,754	(1,041)
Income (loss) from discontinued operations	33	(109)	142
Net income	$ 746	$ 1,645	$ (899)

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

- 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 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.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2013	Years Ended December 31, 2012	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 87	$ 65	$ 22
FEP	55	55	—
PES	(48)	24	(72)
MEP	40	41	(1)
HPC	30	34	(4)
AmeriGas	50	(4)	54
Other	22	(3)	25
Total equity in earnings of unconsolidated affiliates	$ 236	$ 212	$ 24
Adjusted EBITDA related to unconsolidated affiliates:			
Citrus	$ 296	$ 228	$ 68
FEP	75	77	(2)
PES	(30)	26	(56)
MEP	100	102	(2)
HPC	51	65	(14)
AmeriGas	175	139	36
Other	55	9	46
Total Adjusted EBITDA related to unconsolidated affiliates	$ 722	$ 646	$ 76
Distributions received from unconsolidated affiliates:			
Citrus	$ 175	$ 88	$ 87
FEP	69	70	(1)
PES	65	—	65
MEP	72	72	—
HPC	238	61	177
AmeriGas	86	94	(8)
Other	27	13	14
Total distributions received from unconsolidated affiliates	$ 732	$ 398	$ 334

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	57	67	(10)
Segment Adjusted EBITDA	$ 521	$ 667	$ (146)

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

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

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

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

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.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates decreased primarily due to the expiration of certain of HPC's contracts that were not renewed as well as an HPC customer declaring bankruptcy on April 1, 2013.

Interstate Transportation and Storage

	Years Ended December 31, 2013	Years Ended December 31, 2012	Change
Natural gas transported (MMBtu/d)	6,417,529	6,844,789	(427,260)
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)	(143)	63
Adjusted EBITDA related to unconsolidated affiliates	471	407	64
Segment Adjusted EBITDA	$ 1,368	$ 1,117	$ 251

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.

Midstream

	Years Ended December 31,		
	2013	2012	Change
Gathered volumes (MMBtu/d):	4,609,359	4,307,166	302,193
NGLs produced (Bbls/d):	198,894	158,989	39,905
Equity NGLs (Bbls/d):	19,340	24,564	(5,224)
Revenues	$ 4,276	$ 3,077	$ 1,199
Cost of products sold	3,130	2,120	1,010
Gross margin	1,146	957	189
Unrealized gains on commodity risk management activities	2	(11)	13
Operating expenses, excluding non-cash compensation expense	(358)	(272)	(86)
Selling, general and administrative, excluding non-cash compensation expense	(29)	(69)	40
Adjusted EBITDA related to discontinued operations	—	15	(15)
Adjusted EBITDA related to unconsolidated affiliates	3	(7)	10
Other	2	—	2
Segment Adjusted EBITDA	$ 766	$ 613	$ 153

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.

Gross Margin. With respect to ETP's legacy assets, gross margin increased due to a $125 million increase in fee-based revenues resulting from increased volumes from production in the Eagle Ford Shale, offset by a $27 million decrease in non fee-based margins due to lower NGL prices on our Southeast Texas system. Gross margin from Regency's gathering and processing assets increased $97 million primarily due to volume growth in south and west Texas and north Louisiana and a full year of contribution from the SUGS assets versus nine months contribution in 2012.

Unrealized (Gains) Losses on Commodity Risk Management Activities. The change in unrealized gains and losses between periods was primarily due to gains recorded by Regency in 2012 primarily due to mark-to-market adjustments on its non-hedged commodity derivatives. The impact from Regency's unrealized gains and losses was partially offset by unrealized gains of $6 million recorded in 2013 related to the de-designation of hedges associated with ETP's legacy midstream assets.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased $46 million due to a full year of activity from the SUGS assets in 2013 versus nine months in 2012. The remainder of the increase was primarily due to additional expenses from assets recently placed in service, particularly from organic growth in Regency’s south and west Texas assets.

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.

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	$ 2,126	$ 650	$ 1,476
Cost of products sold	1,654	361	1,293
Gross margin	472	289	183
Unrealized gains on commodity risk management activities	(1)	—	(1)
Operating expenses, excluding non-cash compensation expense	(110)	(63)	(47)
Selling, general and administrative expenses, excluding non-cash compensation expense	(16)	(17)	1
Adjusted EBITDA related to unconsolidated affiliates	5	—	5
Segment Adjusted EBITDA	$ 350	$ 209	$ 141

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 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.

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	$ 2,597	$ 1,762	$ 835
Cost of products sold	2,337	1,511	826
Gross margin	260	251	9
Unrealized (gains) losses on commodity risk management activities	(2)	5	(7)
Operating expenses, excluding non-cash compensation expense	(104)	(123)	19
Selling, general and administrative expenses, excluding non-cash compensation expense	(148)	(155)	7
Adjusted EBITDA related to discontinued operations	76	84	(8)
Adjusted EBITDA related to unconsolidated affiliates	147	166	(19)
Other	(2)	—	(2)
Elimination	(24)	(23)	(1)
Segment Adjusted EBITDA	$ 203	$ 205	$ (2)

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 Coal Handling, an entity that owns and operates end-user coal handling facilities.

For the year ended December 31, 2013 compared to the year ended December 31, 2012, Segment Adjusted EBITDA increased due to the net impact of the following:

- an increase of $10 million in gross margin primarily related to Regency's contract services operations, as a result of increased revenue generating horsepower; and
- a decrease in operating expenses 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; offset by
- a decrease of $8 million in adjusted EBITDA related to discontinued operations, which reflected the results of Southern Union's local distribution operations; and
- a decrease of $20 million in adjusted EBITDA related to unconsolidated affiliates due to a decrease in $56 million related to lower earnings from our investment in PES, offset by an increase of $36 million related to higher earnings from our investment in AmeriGas.

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.

In accordance with GAAP, we have accounted for the Regency Merger as a reorganizations of entities under common control. Accordingly, ETP's consolidated financial information reflects the retrospective consolidation of Regency into ETP beginning May 26, 2010 (the date ETE obtained control of Regency).

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	$ 16,964	$ (93)	$ 35,258	$ 443	$ (12,174)	$ 40,398
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	14,205	(80)	33,142	302	(11,193)	36,376
Depreciation and amortization	858	(4)	168	49	76	1,147
Selling, general and administrative	476	(1)	459	11	(119)	826
Impairment charges	—		124		(22)	102
Total costs and expenses	15,539	(85)	33,893	362	(11,258)	38,451
OPERATING INCOME	1,425	(8)	1,365	81	(916)	1,947
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(788)	(24)	(123)	(50)	2	(983)
Equity in earnings of affiliates	212	19	41	16	5	293
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	(124)	115	—	—	—	(9)
Losses on interest rate derivatives	(4)	—	—	—	—	(4)
Other, net	39	2	118	(2)	(2)	155
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	1,817	(953)	2,545	45	(2,055)	1,399
Income tax expense (benefit)	63	—	956	12	(871)	160
INCOME FROM CONTINUING OPERATIONS	$ 1,754	$ (953)	$ 1,589	$ 33	$ (1,184)	$ 1,239

(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.
- 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 capital expenditures (net of contributions in aid of construction costs) for the full year 2015 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage	$ 130	$ 180	$ 30	$ 35
Interstate transportation and storage[2]	700	750	130	140
Midstream	1,900	2,000	90	110
Liquids transportation and services:				
NGL	1,550	1,600	20	25
Crude[2]	800	850	—	—
Retail marketing[3]	160	210	55	75
All other (including eliminations)	200	250	35	45
Total direct capital expenditures	5,440	5,840	360	430
Indirect[1]:				
Investment in Sunoco Logistics	2,400	2,600	65	75
Investment in Sunoco LP[4]	220	270	40	50
Total indirect capital expenditures	2,620	2,870	105	125
Total projected capital expenditures	$ 8,060	$ 8,710	$ 465	$ 555

(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) 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 $663 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 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.

On April 30, 2015, in connection with th Regency Merger, the Regency Credit Facility was paid off in full and terminated.

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, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion 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 $3.17 billion and net income was $1.30 billion. The difference between net income and cash provided by operating activities in 2014 primarily consisted of non-cash items totaling $1.92 billion offset by net changes in operating assets and liabilities of $320 million. The non-cash activity in 2014 consisted primarily of depreciation, depletion and amortization of $1.67 billion, inventory valuation adjustments of $473 million and a goodwill impairment of $370 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 $2.63 billion and net income was $746 million. The difference between net income and cash provided by operating activities in 2013 primarily consisted of non-cash items totaling $1.74 billion offset by net changes in operating assets and liabilities of $158 million. The non-cash activity in 2013 consisted primarily of depreciation, depletion and amortization of $1.30 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 $1.41 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 $493 million offset by non-cash items totaling $1.11 billion. The non-cash activity in 2012 consisted primarily of depreciation, depletion and amortization, including amounts related to discontinued operations, of $858 million, the write-down of assets included in loss from discontinued operations of $132 million, loss on extinguishment of debt of $124 million, inventory valuation adjustments of $75 million and non-cash compensation expense of $47 million.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2014

Cash used in investing activities in 2014 was $6.69 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $5.17 billion. Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $2.37 billion for acquisitions, primarily for the Eagle Rock Acquisition, 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 $3.64 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $3.42 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, we received $1.01 billion and $346 million in cash from 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 $2.66 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $3.24 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.

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	1,204	94	1,298	(40)	1,258
Liquids transportation and services	406	21	427	(15)	412
Retail marketing[2]	104	73	177	1	178
All other (including eliminations)	391	29	420	19	439
Total direct capital expenditures	2,539	363	2,902	(180)	2,722
Indirect[1]:					
Investment in Sunoco Logistics	2,434	76	2,510	(146)	2,364
Investment in Sunoco LP[2]	77	5	82	—	82
Total indirect capital expenditures	2,511	81	2,592	(146)	2,446
Total capital expenditures	$ 5,050	$ 444	$ 5,494	$ (326)	$ 5,168
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	1,033	81	1,114	87	1,201
Liquids transportation and services	426	22	448	84	532
Retail marketing	113	63	176	(1)	175
All other (including eliminations)	326	46	372	26	398
Total direct capital expenditures	1,971	338	2,309	211	2,520
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	$ 2,936	$ 391	$ 3,327	$ 90	$ 3,417
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	1,563	70	1,633	(153)	1,480
Liquids transportation and services	1,288	18	1,306	(75)	1,231
Retail marketing	38	20	58	(19)	39
All other (including eliminations)	166	61	227	(53)	174
Total direct capital expenditures	3,068	326	3,394	(297)	3,097
Indirect[1]:					
Investment in Sunoco Logistics	118	21	139	—	139
Total indirect capital expenditures	118	21	139	—	139
Total capital expenditures	$ 3,186	$ 347	$ 3,533	$ (297)	$ 3,236

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

(2) 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 $3.62 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 $2.65 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 $63 million. In 2014, we paid distributions of $1.96 billion to our partners and we paid distributions of $241 million to noncontrolling interests. Regency received net proceeds of $1.24 billion from the issuance of common units and paid distributions of $645 million to its partners.

Year Ended December 31, 2013

Cash provided by financing activities was $1,220 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 $1,988 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 $57 million. In 2013, we paid distributions of $1.80 billion to our partners and we paid distributions of $303 million to noncontrolling interests. Regency received net proceeds of $149 million from the issuance of common units and paid distributions of $342 million to its partners.

Year Ended December 31, 2012

Cash provided by financing activities was $1.52 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 $2.24 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. Regency received net proceeds of $312 million from the issuance of common units and paid distributions of $322 million to its partners.

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
Regency Senior Notes	5,089	2,800
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	—
Regency $2.0 billion Revolving Credit Facility due November 25, 2019	1,504	510
Other long-term debt	223	228
Unamortized premiums, net of discounts and fair value adjustments	280	308
Total debt	25,981	20,398
Less: current maturities of long-term debt	1,008	637
Long-term debt, less current maturities	$ 24,973	$ 19,761

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.

ETP Senior Notes

In June 2015, ETP issued $650 million aggregate principal amount of 2.50% senior notes due June 2018, $350 million aggregate principal amount of 4.15% senior notes due October 2020, $1.0 billion aggregate principal amount of 4.75% senior notes due January 2026 and $1.0 billion aggregate principal amount of 6.125% senior notes due December 2045. ETP used the net proceeds of $2.98 billion from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

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.

Sunoco LP Senior Notes

In April 2015, Sunoco LP issued $800 million aggregate principal amount of 6.375% senior notes due April 2023. The net proceeds from the offering were used to fund the cash portion of the dropdown of Sunoco, LLC interests and to repay outstanding balances under the Sunoco LP revolving credit facility.

In July 2015, Sunoco LP issued $600 million aggregate principal amount of 5.5% senior notes due August 2020. The net proceeds from the offering were used to fund a portion of the cash consideration for Sunoco LP's acquisition of Susser.

Regency Senior Notes

In February 2014, Regency issued $900 million aggregate principal amount of 5.875% senior notes due March 1, 2022.

In March 2014, as part of the PVR Acquisition, Regency assumed the outstanding senior notes of PVR with an aggregate notional amount of $1.2 billion. The PVR senior notes consisted of $300 million principal amount of 8.25% senior notes due April 15, 2018, $400 million principal amount of 6.5% senior notes due May 15, 2021, and $473 million principal amount of 8.375% senior notes due June 1, 2020. In April 2014, Regency redeemed all of the $300 million principal amount of 8.25% senior notes due April 15, 2018 for $313 million in cash. In July 2014, Regency redeemed $83 million of the $473 million principal amount of 8.375% senior notes due June 1, 2020 for $91 million, including $8 million of accrued interest and redemption premium.

In July 2014, Regency exchanged $499 million aggregate principal amount of 8.375% senior notes due 2019 of Eagle Rock and Eagle Rock Energy Finance Corp. for 8.375% senior notes due 2019 issued by Regency and its wholly-owned subsidiary.

In July 2014, Regency issued $700 million aggregate principal amount of 5.0% senior notes that mature on October 1, 2022.

In December 2014, Regency redeemed all of the outstanding $600 million senior notes due 2018, for a total price of $621 million.

On June 1, 2015, Regency redeemed all of the outstanding $499 million aggregate principal amount of its 8.375% senior notes due June 2019.

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

The senior notes issued by Regency are fully and unconditionally guaranteed, on a joint and several basis, by all of Regency's consolidated subsidiaries, except for ELG and its wholly-owned subsidiaries, Aqua – PVR and ORS. As a result, excluding ELG, Aqua – PVR and ORS, the Regency senior notes effectively rank junior to any future indebtedness of Regency's or its subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the Regency senior notes effectively rank junior to all indebtedness and other liabilities of Regency's existing and future subsidiaries.

Panhandle previously agreed to fully and unconditionally guarantee (the "Panhandle Guarantee") all of the payment obligations of Regency and Regency Energy Finance Corp. under their $600 million in aggregate principal amount of 4.50% senior notes due November 2023. On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it has agreed to become a co-obligor with respect to the payment obligations thereunder. Accordingly, pursuant to the terms of the senior notes, Panhandle's obligations under the Panhandle Guarantee have been released.

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%.

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.

In March 2015, Sunoco Logistics amended and restated its unsecured credit facility, which was scheduled to mature in November 2018. The amended and restated credit facility is a $2.5 billion unsecured revolving credit agreement, which matures in March 2020.

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.

In April 2015, Sunoco LP amended the Sunoco LP Credit Facility to allow for borrowings of up to $1.5 billion.

Regency Credit Facility

The Regency Credit Facility had aggregate revolving commitments of $2.0 billion, with a $500 million incremental facility. The maturity date of the Regency Credit Facility was November 25, 2019.

The outstanding balance of revolving loans under the Regency Credit Facility bore interest at LIBOR plus a margin or an alternate base rate. The alternate base rate used to calculate interest on base rate loans was calculated using the greater of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin ranged from 0.625% to 1.50% for base rate loans and 1.625% to 2.50% for Eurodollar loans.

Regency paid (i) a commitment fee ranging between 0.30% and 0.45% per annum for the unused portion of the revolving loan commitments; (ii) a participation fee for each revolving lender participating in letters of credit ranging between 1.625% and 2.50% per annum of the average daily amount of such lender's letter of credit exposure and; (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of its letter of credit exposure. The Regency Credit Facility allowed for investments in its joint ventures.

As of December 31, 2014, Regency had a balance outstanding of $1.50 billion under the Regency Credit Facility in revolving credit loans and approximately $23 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2014, which is reduced by any letters of credit, was approximately $473 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 2.17%. On April 30, 2015, in connection with the Regency Merger, the Regency Credit Facility was paid off in full and terminated.

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."

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.

Covenants Related to Regency

The Regency senior notes contain various covenants that limit, among other things, Regency's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the Regency senior notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, Regency will no longer be subject to these covenants except that the lien covenant will continue to be applicable. ETP has advised Regency that it intends to provide an ETP guarantee with respect to the outstanding Regency senior notes upon the closing of the Regency Merger, and it is expected that this will result in the Regency senior notes being upgraded an investment grade rating by both Moody's and SAP.

The Regency Credit Facility contained the following financial covenants:

- Regency's consolidated EBITDA ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 5.00 to 1.
- Regency's consolidated EBITDA to consolidated interest expense, as defined in the credit agreement governing the Regency Credit Facility, must be greater than 2.50 to 1.
- Regency's consolidated senior secured leverage ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 3.25 to 1.

The Regency Credit Facility also contained various covenants that limit, among other things, the ability of Regency and RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the credit agreement governing the Regency Credit Facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the Regency Credit Facility or reasonable extensions thereof.

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").

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.

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	$ 25,701	$ 1,050	$ 1,542	$ 5,417	$ 17,692
Interest on long-term debt[(1)]	15,958	1,387	2,655	2,364	9,552
Payments on derivatives	159	20	83	50	6
Purchase commitments[(2)]	13,518	7,703	3,168	1,188	1,459
Transportation, natural gas storage and fractionation contracts	92	29	43	20	—
Operating lease obligations	1,438	149	243	209	837
Distributions and redemption of ETP Series A Preferred Units[(3)]	96	3	7	7	79
Other[(4)]	344	174	77	57	36
Total[(5)]	$ 57,306	$ 10,515	$ 7,818	$ 9,312	$ 29,661

(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) Assumes the outstanding ETP Series A Preferred Units are redeemed for cash on September 2, 2029.

(4) 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.

(5) Excludes non-current deferred tax liabilities of $4.25 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by ETP

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

Distributions declared 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
March 31, 2015	May 8, 2015	May 15, 2015	1.0150
June 30, 2015	August 6, 2015	August 14, 2015	1.0350

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

ETE agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units. The relinquishments subsequent to the Regency Merger were as follows:

	Total Year
2015 (for quarters ending subsequent to the Regency Merger on April 30, 2015)	$ 56
2016	137
2017	128
2018	105
2019	95

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
March 31, 2015	May 11, 2015	May 15, 2015	0.4190
June 30, 2015	August 10, 2015	August 14, 2015	0.4380

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.

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
March 31, 2015	May 19, 2015	May 29, 2015	0.6450
June 30, 2015	August 18, 2015	August 28, 2015	0.6934

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

Cash Distributions Paid by Regency

Regency's partnership agreement requires that Regency distribute all of its Available Cash to its Unitholders and its General Partner within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the general partner. The term Available Cash generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

Distributions declared by Regency during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 6, 2012	February 13, 2012	$ 0.4600
March 31, 2012	May 7, 2012	May 14, 2012	0.4600
June 30, 2012	August 6, 2012	August 14, 2012	0.4600
September 30, 2012	November 6, 2012	November 14, 2012	0.4600
December 31, 2012	February 7, 2013	February 14, 2013	0.4600
March 31, 2013	May 6, 2013	May 13, 2013	0.4600
June 30, 2013	August 5, 2013	August 14, 2013	0.4650
September 30, 2013	November 4, 2013	November 14, 2013	0.4700
December 31, 2013	February 7, 2014	February 14, 2014	0.4750
March 31, 2014	May 8, 2014	May 15, 2014	0.4800
June 30, 2014	August 7, 2014	August 14, 2014	0.4900
September 30, 2014	November 4, 2014	November 14, 2014	0.5025
December 31, 2014	February 6, 2015	February 13, 2015	0.5025

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

	Years Ended December 31,		
	2014	2013	2012
Limited Partners	$ 775	$ 390	$ 314
General Partner Interest	6	5	5
Incentive distributions	33	12	8
IDR relinquishments related to previous transactions	(3)	(3)	—
Total Regency distributions	$ 811	$ 404	$ 327

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 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.

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, 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.

Regency earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, (iii) contract compression services and (iv) contract treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression services, revenue is recognized when the service is performed. For gathering and processing services, Regency receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percent-of-proceeds contract type, Regency is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, Regency earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas at a price approximating the index price and NGLs to third parties. Regency generally reports revenue gross when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net because Regency takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

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 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.

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 12 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 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,” “could,” “believe,” “may,” “will” and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;

- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Item 1A. Risk Factors” in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

Inflation

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Regency is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand, as well as market forces. Regency's profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect its ability to make distributions to its unitholders. Regency manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, Regency may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions are prohibited under Regency's policy.

The table below summarizes the commodity-related financial derivative instruments and fair values related to ETP's legacy operations and Regency's operations, 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.

ETP Legacy Operations

	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)	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.

Regency Operations

	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						
(Non-Trading)						
Natural Gas (MMBtu) — Fixed Swaps/Futures	(25,525,000)	$ 26	$ 8	(24,455,000)	$ (2)	$ 10
Propane (Gallons) — Forwards/Swaps	(29,148,000)	17	1	(52,122,000)	(3)	6
NGLs (Barrels) — Forwards/Swaps	(292,000)	6	1	(438,000)	1	2
WTI Crude Oil (Barrels) — Forwards/Swaps	(1,252,000)	36	7	(521,000)	(1)	5

The fair values of the commodity-related financial positions in the tables above have been determined using independent third party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of December 31, 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 $20 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.

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.

Regency's business operations expose it to credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to Regency's overall profitability. Regency monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a parent company guarantee.

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.

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.

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)	August 12, 2015
/s/ Thomas E. Long Thomas E. Long	Chief Financial Officer (Principal Financial Officer)	August 12, 2015
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	President, Chief Operating Officer and Director	August 12, 2015
/s/ A. Troy Sturrock A. Troy Sturrock	Vice President, Controller (Principal Accounting Officer)	August 12, 2015
/s/ Jamie Welch Jamie Welch	Director	August 12, 2015
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	August 12, 2015
/s/ Michael K. Grimm Michael K. Grimm	Director	August 12, 2015
/s/ James R. Perry James R. Perry	Director	August 12, 2015
/s/ David K. Skidmore David K. Skidmore	Director	August 12, 2015

INDEX TO FINANCIAL STATEMENTS
Energy Transfer Partners, L.P. and Subsidiaries

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 8 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 19 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.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control.

/s/ GRANT THORNTON LLP

Dallas, Texas
August 12, 2015

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

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 663	$ 568
Accounts receivable, net	3,360	3,658
Accounts receivable from related companies	139	117
Inventories	1,460	1,807
Exchanges receivable	44	67
Price risk management assets	81	39
Other current assets	296	311
Total current assets	6,043	6,567
PROPERTY, PLANT AND EQUIPMENT	43,404	33,449
ACCUMULATED DEPRECIATION AND DEPLETION	(4,497)	(3,113)
	38,907	30,336
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,760	4,050
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	10	18
GOODWILL	7,642	5,856
INTANGIBLE ASSETS, net	5,526	2,250
OTHER NON-CURRENT ASSETS, net	786	823
Total assets	$ 62,674	$ 49,900

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

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

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Drafts payable	$ 15	$ 98
Accounts payable	3,333	3,735
Accounts payable to related companies	25	25
Exchanges payable	183	285
Price risk management liabilities	21	53
Accrued and other current liabilities	2,099	1,634
Current maturities of long-term debt	1,008	637
Total current liabilities	6,684	6,467
LONG-TERM DEBT, less current maturities	24,973	19,761
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	154	73
DEFERRED INCOME TAXES	4,246	3,784
OTHER NON-CURRENT LIABILITIES	1,258	1,089
COMMITMENTS AND CONTINGENCIES		
SERIES A PREFERRED UNITS	33	32
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	5,153	3,780
Predecessor equity	8,088	3,374
Total equity	25,311	18,694
Total liabilities and equity	$ 62,674	$ 49,900

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

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	$ 5,386	$ 3,842	$ 2,704
NGL sales	5,845	3,618	2,253
Crude sales	16,416	15,477	2,872
Gathering, transportation and other fees	3,517	3,097	2,387
Refined product sales	19,437	18,479	5,299
Other	4,874	3,822	1,449
Total revenues	55,475	48,335	16,964
COSTS AND EXPENSES:			
Cost of products sold	48,389	42,554	13,088
Operating expenses	2,084	1,695	1,117
Depreciation, depletion and amortization	1,669	1,296	858
Selling, general and administrative	520	482	476
Goodwill impairment	370	689	—
Total costs and expenses	53,032	46,716	15,539
OPERATING INCOME	2,443	1,619	1,425
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(1,165)	(1,013)	(788)
Equity in earnings of unconsolidated affiliates	332	236	212
Gain on deconsolidation of Propane Business	—	—	1,057
Gain on sale of AmeriGas common units	177	87	—
Loss on extinguishment of debt	(25)	(7)	(124)
Gains (losses) on interest rate derivatives	(157)	44	(4)
Non-operating environmental remediation	—	(168)	—
Other, net	(12)	12	39
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,593	810	1,817
Income tax expense from continuing operations	358	97	63
INCOME FROM CONTINUING OPERATIONS	1,235	713	1,754
Income (loss) from discontinued operations	64	33	(109)
NET INCOME	1,299	746	1,645
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	116	255	37
LESS: NET INCOME (LOSS) ATTRIBUTABLE TO PREDECESSOR	(153)	35	39
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.

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

	Years Ended December 31,		
	2014	2013	2012
Net income	$ 1,299	$ 746	$ 1,645
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)	(16)
Change in value of derivative instruments accounted for as cash flow hedges	—	(1)	12
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	(23)
Comprehensive income	1,182	825	1,622
Less: Comprehensive income attributable to noncontrolling interest	116	255	31
Less: Comprehensive income (loss) attributable to predecessor	(153)	35	41
Comprehensive income attributable to partners	$ 1,219	$ 535	$ 1,550

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

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	Predecessor Equity	Total
Balance, December 31, 2011	$ 182	$ 5,533	$ —	$ 6	$ 33	$ 3,493	$ 9,247
Distributions to partners	(454)	(889)	—	—	—	—	(1,343)
Predecessor distributions to partners	—	—	—	—	—	(322)	(322)
Distributions to noncontrolling interest	—	—	—	—	(165)	—	(165)
Units issued for cash	—	791	—	—	—	—	791
Predecessor units issued for cash	—	—	—	—	—	312	312
Capital contributions from noncontrolling interest	—	—	—	—	42	—	42
Sunoco Merger	—	2,288	—	—	3,580	—	5,868
ETP Holdco Transaction	—	165	—	—	3,748	—	3,913
Issuance of units in other acquisitions (excluding Sunoco, Inc.)	—	7	—	—	—	—	7
Other comprehensive loss, net of tax	—	—	—	(19)	(6)	2	(23)
Other, net	(1)	23	—	—	(9)	(3)	10
Net income	461	1,108	—	—	37	39	1,645
Balance, December 31, 2012	188	9,026	—	(13)	7,260	3,521	19,982
Distributions to partners	(523)	(1,228)	(51)	—	—	—	(1,802)
Predecessor distributions to partners	—	—	—	—	—	(342)	(342)
Distributions to noncontrolling interest	—	—	—	—	(303)	—	(303)
Units issued for cash	—	1,611	—	—	—	—	1,611
Predecessor units issued for cash	—	—	—	—	—	149	149
Issuance of Class H Units	—	(1,514)	1,514	—	—	—	—
Capital contributions from noncontrolling interest	—	—	—	—	18	—	18
ETP Holdco Acquisition and SUGS Contribution	—	2,013	—	(5)	(3,448)	—	(1,440)
Other comprehensive income, net of tax	—	—	—	79	—	—	79
Other, net	—	(13)	—	—	(2)	11	(4)
Net income (loss)	506	(98)	48	—	255	35	746
Balance, December 31, 2013	171	9,797	1,511	61	3,780	3,374	18,694
Distributions to partners	(500)	(1,252)	(212)	—	—	—	(1,964)
Predecessor distributions to partners	—	—	—	—	—	(645)	(645)
Distributions to noncontrolling interest	—	—	—	—	(241)	—	(241)
Units issued for cash	—	1,382	—	—	—	—	1,382
Subsidiary units issued for cash	1	174	—	—	1,069	—	1,244
Predecessor units issued for cash	—	—	—	—	—	1,227	1,227
Capital contributions from noncontrolling interest	—	—	—	—	67	—	67
Lake Charles LNG Transaction	—	(1,167)	—	—	—	—	(1,167)
Susser Merger	—	908	—	—	626	—	1,534
Sunoco Logistics acquisition of a noncontrolling interest	(1)	(79)	—	—	(245)	—	(325)
Predecessor equity issued for Hoover, net of cash received	—	—	—	—	—	109	109
Predecessor equity issued for PVR, net of cash received	—	—	—	—	—	3,906	3,906
Predecessor equity issued for Eagle Rock, net of cash received	—	—	—	—	—	266	266
Other comprehensive loss, net of tax	—	—	—	(117)	—	—	(117)
Other, net	—	61	(4)	—	(19)	4	42
Net income (loss)	513	606	217	—	116	(153)	1,299
Balance, December 31, 2014	$ 184	$ 10,430	$ 1,512	$ (56)	$ 5,153	$ 8,088	$ 25,311

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

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	$ 1,299	$ 746	$ 1,645
Reconciliation of net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,669	1,296	858
Deferred income taxes	(49)	48	62
Amortization included in interest expense	(60)	(72)	(28)
Inventory valuation adjustments	473	(3)	75
Non-cash compensation expense	68	54	47
Goodwill impairment	370	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	25	7	124
Write-down of assets included in loss from discontinued operations	—	—	132
Distributions on unvested awards	(16)	(12)	(8)
Equity in earnings of unconsolidated affiliates	(332)	(236)	(212)
Distributions from unconsolidated affiliates	291	313	208
Other non-cash	(72)	42	68
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	(320)	(158)	(493)
Net cash provided by operating activities	3,169	2,627	1,406
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Susser Merger, net of cash received	(808)	—	—
Cash paid for Eagle Rock Acquisition, net of cash received	(577)	—	—
Cash paid for Hoover Acquisition, net of cash received	(185)	—	—
Cash paid for acquisition of a noncontrolling interest	(325)	—	—
Cash paid for ETP Holdco Acquisition	—	(1,332)	—
Cash paid for Citrus Merger	—	—	(1,895)
Cash proceeds from the sale of AmeriGas common units	814	346	—
Cash proceeds from contribution and sale of propane operations	—	—	1,443
Cash (paid) received from all other acquisitions	(472)	(405)	531
Capital expenditures (excluding allowance for equity funds used during construction)	(5,213)	(3,469)	(3,271)
Contributions in aid of construction costs	45	52	35
Contributions to unconsolidated affiliates	(399)	(3)	(65)
Distributions from unconsolidated affiliates in excess of cumulative earnings	136	419	190
Proceeds from sale of discontinued operations	77	1,008	207
Proceeds from the sale of assets	61	68	44
Change in restricted cash	172	(348)	5
Other	(18)	21	112
Net cash used in investing activities	(6,692)	(3,643)	(2,664)

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

CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	15,354	10,854	10,762
Repayments of long-term debt	(12,702)	(8,700)	(8,685)
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	—	—
Predecessor equity offerings, net of issuance costs	1,227	149	312
Capital contributions received from noncontrolling interest	67	18	42
Distributions to partners	(1,964)	(1,802)	(1,343)
Predecessor distributions to partners	(645)	(342)	(322)
Distributions to noncontrolling interest	(241)	(303)	(165)
Debt issuance costs	(63)	(57)	(35)
Other	(41)	(42)	(8)
Net cash provided by financing activities	3,618	1,220	1,515
INCREASE IN CASH AND CASH EQUIVALENTS	95	204	257
CASH AND CASH EQUIVALENTS, beginning of period	568	364	107
CASH AND CASH EQUIVALENTS, end of period	$ 663	$ 568	$ 364

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar 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.

As discussed in Note 3, ETP and Regency merged in April 2015. ETP and Regency were under common control of ETE; therefore, we accounted for the Regency Merger at historical cost as a reorganization of entities under common control. In accordance with GAAP, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner). Predecessor equity included on the consolidated financial statements represents Regency's equity prior to the Regency Merger.

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 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.
- 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 as of December 31, 2014. 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.
- Regency is a limited partnership engaged in the gathering and processing, compression, treating and transportation of natural gas; the transportation, fractionation and storage of NGLs (until June 1, 2015); the gathering, transportation and terminaling of oil (crude and/or condensate, a lighter oil) received from producers; natural gas and NGL marketing and trading, and the management of coal and natural resource properties in the United States. Regency focuses on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring, Avalon and Granite Wash shales.

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 February 2015, the FASB issued Accounting Standards Update No. 2015-02, *Consolidation (Topic 810)* ("ASU 2015-02"), which changed the requirements for consolidations analysis. Under ASU 2015-02, reporting entities are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for fiscal years beginning after December 15, 2015, and early adoption is permitted. The Partnership expects to adopt this standard for the year ending December 31, 2016, and we are currently evaluating the impact that it will have on the consolidated financial statements and related disclosures.

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 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 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.

Regency earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas, NGL, condensate and salt water gathering, processing and transportation, (iii) contract compression and treating services and (iv) coal royalties. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, Regency receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, Regency is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, Regency earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. Regency generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because Regency takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Regency recognizes coal royalties revenues on the basis of tons of coal sold by its lessees and the corresponding revenues from those sales. Regency does not have access to actual production and revenues information until 30 days following the month of production. Therefore, financial results include estimated revenues and accounts receivable for the month of production. Regency records any differences between the actual amounts ultimately received or paid and the original estimates in the period they become finalized. Most lessees must make minimum monthly or annual payments that are generally recoverable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recovers a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalties revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues, which is a component of other revenues on our consolidated statements of operations. Other liabilities on the balance sheet also include deferred unearned income from a coal services facility lease, which is recognized as other income as it is earned.

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.

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	$ 600	$ (557)	$ 267
Accounts receivable from related companies	(22)	26	(12)
Inventories	51	(254)	(258)
Exchanges receivable	18	(8)	14
Other current assets	132	(58)	574
Other non-current assets, net	(6)	(45)	(30)
Accounts payable	(851)	542	(990)
Accounts payable to related companies	3	(143)	101
Exchanges payable	(99)	128	—
Accrued and other current liabilities	(92)	211	(169)
Other non-current liabilities	(73)	147	25
Price risk management assets and liabilities, net	19	(147)	(15)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (320)	$ (158)	$ (493)

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	$ 643	$ 226	$ 420
Net gains from subsidiary common unit issuances	$ 175	$ —	$ —
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	$ —
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 564	$ —	$ 6,658
Issuance of Common Units in connection with other acquisitions	$ —	$ —	$ 2,295
Predecessor equity issuance of common units in connection with PVR, Hoover and Eagle Rock Midstream acquisitions	$ 4,281	$ —	$ —
Long-term debt assumed in PVR Acquisition	$ 1,887	$ —	$ —
Long-term debt exchanged in Eagle Rock Midstream Acquisition	$ 499	$ —	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,232	$ 1,049	$ 790
Cash paid for income taxes	$ 344	$ 58	$ 23

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 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	$ 392	$ 577
Crude oil	364	488
Refined products	392	543
Appliances, parts and fittings, and other	312	199
Total inventories	$ 1,460	$ 1,807

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	217	262
Total other current assets	$ 296	$ 311

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 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	$ 1,307	$ 881
Buildings and improvements (1 to 45 years)	1,918	935
Pipelines and equipment (5 to 83 years)	27,164	21,038
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)	58	1,697
Retail equipment (2 to 99 years)	515	450
Vehicles (1 to 25 years)	203	156
Right of way (20 to 83 years)	2,445	2,183
Furniture and fixtures (2 to 25 years)	57	51
Linepack	119	118
Pad gas	44	52
Natural resources	454	—
Other (1 to 30 years)	979	706
Construction work-in-process	4,343	2,166
	43,404	33,449
Less – Accumulated depreciation	(4,497)	(3,113)
Property, plant and equipment, net	$ 38,907	$ 30,336

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

	Years Ended December 31,		
	2014	2013	2012
Depreciation expense	$ 1,459	$ 1,202	$ 783
Capitalized interest, excluding AFUDC	$ 101	$ 45	$ 99

Depletion expense related to Regency’s natural resources operations was $11 million for the year ended December 31, 2014. Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of coal extracted as compared to the total estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by Regency’s own geologists. Regency’s estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. From time to time, Regency carries out core-hole drilling activities on coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-hole drilling activities are expensed as incurred. Regency depletes timber using a methodology consistent with the units-of-production method, which is based on the quantity of timber harvested. Regency determines depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves.

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 transportation and services and retail marketing segments and all others, including all of Regency's reporting units. 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	$ 688	$ 432	$ 1,368	$ 1,272	$ 742	$ 6,396
Goodwill acquired	—	—	—	—	—	156	—	156
Goodwill impairment	—	(689)	—	—	—	—	—	(689)
Other	—	—	(2)	—	(22)	17	—	(7)
Balance, December 31, 2013	10	1,195	686	432	1,346	1,445	742	5,856
Goodwill acquired	—	—	451	—	12	1,862	15	2,340
Goodwill disposed	—	(184)	—	—	—	—	—	(184)
Goodwill impairment	—	—	(370)	—	—	—	—	(370)
Balance, December 31, 2014	$ 10	$ 1,011	$ 767	$ 432	$ 1,358	$ 3,307	$ 757	$ 7,642

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 $1.79 billion during the year ended December 31, 2014 primarily due to the Susser Merger and PVR Acquisition where we recorded goodwill of $1.73 billion and $370 million, respectively, offset by an impairment of $370 million, as discussed below. The additional goodwill recorded during the years ended December 31, 2014 and 2013 is not expected to be deductible for tax purposes.

During the fourth quarter of 2014, a $370 million goodwill impairment was recorded related to Regency's Permian Basin gathering and processing operations. The decline in estimated fair value of that reporting unit was primarily driven by the significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses. An assessment of these factors in the fourth quarter of 2014 led to a conclusion that the estimated fair value of Regency's Permian reporting unit was less than its carrying amount.

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.

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)	$ 5,067	$ (464)	$ 2,113	$ (256)
Patents (9 years)	48	(11)	48	(6)
Trade Names (15 years)	556	(15)	66	(12)
Other (1 to 15 years)	36	(7)	7	(4)
Total amortizable intangible assets	$ 5,707	$ (497)	$ 2,234	$ (278)
Non-amortizable intangible assets:				
Trademarks	316	—	294	—
Total intangible assets	$ 6,023	$ (497)	$ 2,528	$ (278)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2014	2013	2012
Reported in depreciation, depletion and amortization	$ 212	$ 117	$ 65

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

Years Ending December 31:	
2015	$ 263
2016	260
2017	260
2018	259
2019	256

The increase in intangible assets during the year ended December 31, 2014 relates to the acquisitions more fully described in Note 3.

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)	$ 156	$ 126
Regulatory assets	85	86
Deferred charges	220	144
Restricted funds	177	378
Other	148	89
Total other non-current assets, net	$ 786	$ 823

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

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	$ 60	$ 55
Investment in Sunoco Logistics	41	41
Retail marketing	87	84
	$ 188	$ 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.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2014	2013
Interest payable	$ 382	$ 332
Customer advances and deposits	103	142
Accrued capital expenditures	673	258
Accrued wages and benefits	233	173
Taxes payable other than income taxes	236	211
Income taxes payable	54	4
Deferred income taxes	99	119
Other	319	395
Total accrued and other current liabilities	$ 2,099	$ 1,634

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 $26.91 billion and $25.98 billion, respectively. As of December 31, 2013, the aggregate fair value and carrying amount of our debt obligations was $21.02 billion and $20.40 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.

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 Measurements at December 31, 2014			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$ 3	$ —	$ 3	$ —
Commodity derivatives:				
Condensate — Forward Swaps	36	—	36	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	19	19	—	—
Swing Swaps IFERC	26	1	25	—
Fixed Swaps/Futures	566	541	25	—
Forward Physical Contracts	1	—	1	—
Power:				
Forwards	3	—	3	—
Futures	4	4	—	—
Natural Gas Liquids — Forwards/Swaps	69	46	23	—
Refined Products — Futures	21	21	—	—
Total commodity derivatives	745	632	113	—
Total assets	$ 748	$ 632	$ 116	$ —
Liabilities:				
Interest rate derivatives	$ (155)	$ —	$ (155)	$ —
Embedded derivatives in the ETP Preferred Units	(16)	—	—	(16)
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	$ (749)	$ (551)	$ (182)	$ (16)

	Fair Value Measurements at December 31, 2013			
	Fair Value Total	Level 1	Level 2	Level 3
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	203	201	2	—
Natural Gas Liquids — Forwards/Swaps	7	5	2	—
Power:				
Power — Forwards	3	—	3	—
Refined Products – Futures	5	5	—	—
Total commodity derivatives	231	217	14	—
Total assets	$ 278	$ 217	$ 61	$ —
Liabilities:				
Interest rate derivatives	$ (95)	$ —	$ (95)	$ —
Embedded derivatives in the Regency Preferred Units	(19)	—	—	(19)
Commodity derivatives:				
Condensate — Forward Swaps	(1)	—	(1)	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	(4)	(4)	—	—
Swing Swaps IFERC	(6)	—	(6)	—
Fixed Swaps/Futures	(206)	(201)	(5)	—
Forward Physical Contracts	(1)	—	(1)	—
Natural Gas Liquids — Forwards/Swaps	(9)	(5)	(4)	—
Power:				
Power — Forwards	(1)	—	(1)	—
Refined Products – Futures	(5)	(5)	—	—
Total commodity derivatives	(233)	(215)	(18)	—
Total liabilities	$ (347)	$ (215)	$ (113)	$ (19)

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.

In 2014, a $370 million goodwill impairment charge was recorded related to the Permian reporting unit within the Gathering and Processing segment. The decline in estimated fair value of that reporting unit is primarily driven by the significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses.

In connection with the closing of the Regency Merger, 1.9 million of Regency’s outstanding series A preferred units were converted into corresponding newly issued ETP Series A Preferred Units. See Note 7 - Series A Preferred Units for further information.

The following table presents the material unobservable inputs used to estimate the fair value of Regency's Preferred Units and the embedded derivatives in Regency's Preferred Units:

	Unobservable Input	December 31, 2014
Embedded derivatives in the Regency Preferred Units	Credit Spread	4.76%
	Volatility	35.80%

Changes in the remaining term of the Preferred Units, U.S. Treasury yields and valuations in related instruments would cause a change in the yield to value the Preferred Units. Changes in Regency's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives in the Regency Preferred Units. Changes in Regency's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents a reconciliation of the beginning and ending balances for our Level 3 financial instruments measured at fair value on a recurring basis using significant unobservable inputs for the year ended December 31, 2014. There were no transfers between the fair value hierarchy levels during the years ended December 31, 2014 or 2013.

Balance, December 31, 2013	$	(19)
Net unrealized gains included in other income (expense)		3
Balance, December 31, 2014	$	(16)

Contributions in Aid of Construction Costs

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

Shipping and Handling Costs

Shipping and handling costs 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.

Issuances of Subsidiary Units

We record changes in our ownership interest of our subsidiaries as equity transactions, with no gain or loss recognized in consolidated net income or comprehensive income. For example, upon our subsidiaries' issuance of common units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interest is adjusted as a change in partners' capital.

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 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.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2015 Transactions

Sunoco LP

In April 2015, Sunoco LP acquired a 31.58% equity interest in Sunoco, LLC from Retail Holdings for $816 million. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. Sunoco LP paid $775 million in cash and issued $41 million of Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP’s common units as of March 20, 2015.

In July 2015, Sunoco LP acquired 100% of Susser from ETP in a transaction valued at $1.93 billion. Sunoco LP paid approximately $967 million in cash and issued 22 million Sunoco LP common units, valued at approximately $967 million, to ETP. In addition, there will be an exchange for 11 million Sunoco LP units owned by Susser for another 11 million new Sunoco LP units to a subsidiary of ETP.

In July 2015, ETE entered into an exchange and repurchase agreement with ETP, pursuant to which ETE would acquire 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, in exchange for the repurchase of 21 million ETP common units owned by ETE. In connection with ETP’s 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which would terminate upon the closing of ETE’s acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE agreed to provide ETP a $35 million annual IDR subsidy for two years. Following this transaction, Sunoco LP will no longer be consolidated for accounting purposes by ETP. This transaction is expected to close in August 2015.

Regency Merger

In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the “Regency Merger”). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common

Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were concerted into corresponding new ETP Series A Preferred Units.

In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will 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.

ETP and Regency were under common control of ETE; therefore, we accounted for the Regency Merger at historical cost as a reorganization of entities under common control. In accordance with GAAP, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner). Predecessor equity included on the consolidated financial statements represents Regency's equity prior to the Regency Merger.

The following table presents the revenues and net income (loss) for the previously separate entities and the combined amounts presented herein:

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Partnership	$ 51,158	$ 46,339	$ 15,702
Regency	4,840	2,242	1,309
Adjustments and eliminations	(523)	(246)	(47)
Combined	$ 55,475	$ 48,335	$ 16,964
Net income (loss):			
Partnership	$ 1,553	$ 767	$ 1,647
Regency	(142)	64	48
Adjustments and eliminations	(112)	(85)	(50)
Combined	$ 1,299	$ 746	$ 1,645

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.

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 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 9.

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.

Regency’s Acquisition of PVR Partners, L.P.

On March 21, 2014, Regency acquired PVR for a total purchase price of $5.7 billion (based on Regency’s closing price of $27.82 per Regency Common Unit on March 21, 2014), including $1.8 billion principal amount of assumed debt (the “PVR Acquisition”). PVR unitholders received (on a per unit basis) 1.02 Regency Common Units and a one-time cash payment of $36 million, which was funded through borrowings under Regency’s revolving credit facility. The PVR Acquisition enhances Regency’s geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region. Regency accounted for the PVR Acquisition 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 statement of operations for the year ended December 31, 2014 included revenues and net income attributable to PVR’s operations of $956 million and $166 million, respectively.

Regency completed the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase price was allocated as follows:

Assets	At March 21, 2014
Current assets	$ 149
Property, plant and equipment	2,716
Investment in unconsolidated affiliates	62
Intangible assets (average useful life of 30 years)	2,717
Goodwill	370
Other non-current assets	18
Total assets acquired	6,032
Liabilities	
Current liabilities	168
Long-term debt	1,788
Premium related to senior notes	99
Non-current liabilities	30
Total liabilities assumed	2,085
Net assets acquired	$ 3,947

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

Regency’s Acquisition of Eagle Rock’s Midstream Business

On July 1, 2014, Regency acquired Eagle Rock’s midstream business (the “Eagle Rock Midstream Acquisition”) for $1.3 billion, including the assumption of $499 million of Eagle Rock’s 8.375% senior notes due 2019. The remainder of the purchase price was funded by $400 million in Regency Common Units sold to a wholly-owned subsidiary of ETE, 8.2 million Regency Common Units issued to Eagle Rock and borrowings under Regency’s revolving credit facility. Regency accounted for the Eagle Rock Midstream Acquisition 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. This acquisition complements Regency's core gathering and processing business and further diversifies Regency's geographic presence in the Mid-Continent region, east Texas and south Texas. Our consolidated statement of operations for the year ended December 31, 2014 included revenues and net income attributable to Eagle Rock's operations of $903 million and $30 million, respectively.

Regency completed the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase price was allocated as follows:

Assets		At July 1, 2014
Current assets	$	113
Property, plant and equipment		1,295
Goodwill[(1)]		59
Total assets acquired		1,467
Liabilities		
Current liabilities		116
Long-term debt		499
Other non-current liabilities		11
Total liabilities assumed		626
Net assets acquired	$	841

(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.

Regency's Acquisition of Hoover Energy

On February 3, 2014, Regency completed its acquistion of certain subsidiaries of Hoover Energy for a total purchase price of $293 million, consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy, (ii) $184 million in cash, and (iii) $2 million in asset retirement obligations assumed.

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"). Prior to the Regency Merger, the general partner and IDRs of Regency were 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 had the same rights, terms and conditions as the Regency common units, except that Southern Union was receiving distributions on the Regency Class F units. These units converted to ETP common units on the date of the Regency Merger.

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 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 9. 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.

(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 years ended December 31, 2014, 2013 and 2012 are presented as if the Sunoco Merger and the ETP Holdco Transaction had been completed on January 1, 2012, and the PVR and Eagle Rock Midstream acquisitions had been completed on January 1, 2013, and assumes there were no other changes in operations.

	Years Ended December 31,		
	2014	2013	2012
Revenues	$ 56,301	$ 50,473	$ 40,397
Net income	1,151	532	1,240
Net income attributable to partners	1,323	423	817
Basic net income per Limited Partner unit	$ 3.99	$ 1.23	$ 3.29
Diluted net income per Limited Partner unit	$ 3.97	$ 1.23	$ 3.28

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 results of PVR and Eagle Rock midstream beginning January 1, 2013;
- 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.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

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.

Midcontinent Express Pipeline LLC

Regency owns a 50% interest in MEP, which owns approximately 500 miles of natural gas pipelines that extend from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. The carrying amount of Regency's investment in MEP was $695 million and $548 million as of December 31, 2014 and 2013, respectively, and was reflected in our interstate transportation and storage segment.

RIGS Haynesville Partnership Co.

Regency owns a 49.99% interest in HPC, which, through its ownership of RIGS, delivers natural gas from Northwest Louisiana to downstream pipelines and markets through a 450-mile intrastate pipeline system. The carrying amount of Regency's investment in HPC was $422 million and $442 million as of December 31, 2014 and 2013, respectively, and was reflected in our intrastate transportation and storage segment.

Summarized Financial Information

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

	December 31, 2014	December 31, 2013
Current assets	$ 889	$ 1,028
Property, plant and equipment, net	10,520	10,778
Other assets	2,687	2,664
Total assets	$ 14,096	$ 14,470
Current liabilities	$ 1,983	$ 1,039
Non-current liabilities	7,359	8,139
Equity	4,754	5,292
Total liabilities and equity	$ 14,096	$ 14,470

	Years Ended December 31, 2014	2013	2012
Revenue	$ 4,925	$ 4,695	$ 4,492
Operating income	1,071	1,197	863
Net income	577	699	491

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

5. NET INCOME PER LIMITED PARTNER UNIT:

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 the General Partner, the holder of the IDRs pursuant to the 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. Earnings attributable to predecessor represents amounts allocated to the former Regency partners and have no impact on income from continuing operations per unit for the periods prior to the Regency Merger.

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	$ 1,235	$ 713	$ 1,754
Less: Income from continuing operations attributable to noncontrolling interest	116	239	20
Less: Income (loss) from continuing operations attributable to predecessor	(153)	35	39
Income from continuing operations, net of noncontrolling interest and predecessor income (loss)	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
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	—
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	—
Regency Debt		
6.875% Senior Notes due December 1, 2018	—	600
5.75% Senior Notes due September 1, 2020	400	400
6.5% Senior Notes due July 15, 2021	500	500
5.875% Senior Notes due March 1, 2022	900	—
5.5% Senior Notes due April 15, 2023	700	700
4.5% Senior Notes due November 1, 2023	600	600
8.375% Senior Notes due June 1, 2020	390	—
6.5% Senior Notes due May 15, 2021	400	—
8.375% Senior Notes due June 1, 2019	499	—
5.0% Senior Notes due October 1, 2022	700	—
Regency $2.0 billion Revolving Credit Facility due November 25, 2019	1,504	510
Unamortized premiums, discounts and fair value adjustments, net	48	—
	6,641	3,310
Other	223	228
	25,981	20,398
Less: current maturities	1,008	637
	$ 24,973	$ 19,761

(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 $280 million in unamortized net premiums and fair value adjustments:

2015	$ 1,050
2016	314
2017	1,228
2018	1,155
2019	4,262
Thereafter	17,692
Total	$ 25,701

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.

In June 2015, ETP issued $650 million aggregate principal amount of 2.50% senior notes due June 2018, $350 million aggregate principal amount of 4.15% senior notes due October 2020, $1.0 billion aggregate principal amount of 4.75% senior notes due January 2026 and $1.0 billion aggregate principal amount of 6.125% senior notes due December 2045. ETP used the net proceeds of $2.98 billion from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

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.

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 LP Senior Notes

In April 2015, Sunoco LP issued $800 million aggregate principal amount of 6.375% senior notes due April 2023. The net proceeds from the offering were used to fund the cash portion of the dropdown of Sunoco, LLC interests and to repay outstanding balances under the Sunoco LP revolving credit facility.

In July 2015, Sunoco LP issued $600 million aggregate principal amount of 5.5% senior notes due August 2020. The net proceeds from the offering were used to fund a portion of the cash consideration for Sunoco LP's acquisition of Susser.

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.

Regency Senior Notes

The Regency senior notes are unsecured obligations of Regency and the obligation of Regency to repay the Regency senior notes is not guaranteed by us or any of Regency's subsidiaries. The Regency senior notes effectively rank junior to all indebtedness and other liabilities of Regency's existing and future subsidiaries. Interest is payable semi-annually.

In February 2014, Regency issued $900 million aggregate principal amount of 5.875% senior notes due March 1, 2022.

In March 2014, as part of the PVR Acquisition, Regency assumed the outstanding senior notes of PVR with an aggregate notional amount of $1.2 billion. The PVR senior notes consisted of $300 million principal amount of 8.25% senior notes due April 15, 2018, $400 million principal amount of 6.5% senior notes due May 15, 2021, and $473 million principal amount of 8.375% senior notes due June 1, 2020. In April 2014, Regency redeemed all of the $300 million principal amount of 8.25% senior notes due April 15, 2018 for $313 million in cash. In July 2014, Regency redeemed $83 million of the $473 million principal amount of 8.375% senior notes due June 1, 2020 for $91 million, including $8 million of accrued interest and redemption premium.

In July 2014, Regency exchanged $499 million aggregate principal amount of 8.375% senior notes due 2019 of Eagle Rock and Eagle Rock Energy Finance Corp. for 8.375% senior notes due 2019 issued by Regency and its wholly-owned subsidiary.

In July 2014, Regency issued $700 million aggregate principal amount of 5.0% senior notes that mature on October 1, 2022.

In December 2014, Regency redeemed all of the outstanding $600 million senior notes due 2018, for a total price of $621 million.

On June 1, 2015, Regency redeemed all of the outstanding $499 million aggregate principal amount of its 8.375% senior notes due June 2019.

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

The senior notes issued by Regency are fully and unconditionally guaranteed, on a joint and several basis, by all of Regency's consolidated subsidiaries, except for ELG and its wholly-owned subsidiaries, Aqua – PVR and ORS. As a result, excluding ELG, Aqua – PVR and ORS, the Regency senior notes effectively rank junior to any future indebtedness of Regency's or its subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the Regency senior notes effectively rank junior to all indebtedness and other liabilities of Regency's existing and future subsidiaries.

Panhandle previously agreed to fully and unconditionally guarantee (the "Panhandle Guarantee") all of the payment obligations of Regency and Regency Energy Finance Corp. under their $600 million in aggregate principal amount of 4.50% senior notes due November 2023. On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it has agreed to become a co-obligor with respect to the payment obligations thereunder. Accordingly, pursuant to the terms of the senior notes, Panhandle's obligations under the Panhandle Guarantee have been released.

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.

In March 2015, Sunoco Logistics amended and restated its unsecured credit facility, which was scheduled to mature in November 2018. The amended and restated credit facility is a $2.5 billion unsecured revolving credit agreement, which matures in March 2020.

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.

In April 2015, Sunoco LP amended the Sunoco LP Credit Facility to allow for borrowings of up to $1.5 billion.

Regency Credit Facility

The Regency Credit Facility had aggregate revolving commitments of $2.0 billion, with a $500 million incremental facility. The maturity date of the Regency Credit Facility was November 25, 2019.

The outstanding balance of revolving loans under the Regency Credit Facility bore interest at LIBOR plus a margin or an alternate base rate. The alternate base rate used to calculate interest on base rate loans was calculated using the greater of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin ranged from 0.625% to 1.50% for base rate loans and 1.625% to 2.50% for Eurodollar loans.

Regency paid (i) a commitment fee ranging between 0.30% and 0.45% per annum for the unused portion of the revolving loan commitments; (ii) a participation fee for each revolving lender participating in letters of credit ranging between 1.625% and 2.50% per annum of the average daily amount of such lender's letter of credit exposure and; (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of its letter of credit exposure. The Regency Credit Facility allowed for investments in its joint ventures.

As of December 31, 2014, Regency had a balance outstanding of $1.50 billion under the Regency Credit Facility in revolving credit loans and approximately $23 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2014, which is reduced by any letters of credit, was approximately $473 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 2.17%. On April 30, 2015, in connection with the Regency Merger, the Regency Credit Facility was paid off in full and terminated.

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 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 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.

Covenants Related to Regency

The Regency senior notes contain various covenants that limit, among other things, Regency's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the Regency senior notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, Regency will no longer be subject to these covenants except that the lien covenant will continue to be applicable. ETP provided a guarantee with respect to the outstanding Regency senior notes upon the closing of the Regency Merger.

The Regency Credit Facility contained the following financial covenants:

- Regency's consolidated EBITDA ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 5.00 to 1.
- Regency's consolidated EBITDA to consolidated interest expense, as defined in the credit agreement governing the Regency Credit Facility, must be greater than 2.50 to 1.
- Regency's consolidated senior secured leverage ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 3.25 to 1.

The Regency Credit Facility also contained various covenants that limit, among other things, the ability of Regency and RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the credit agreement governing the Regency Credit Facility);
- issue capital stock or create subsidiaries; or

- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the Regency Credit Facility or reasonable extensions thereof.

Regency Credit Facility was paid off and terminated by ETP in connection with the Regency Merger.

Compliance with our Covenants

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

7. SERIES A PREFERRED UNITS:

In connection with the closing of the Regency Merger, 1.9 million of Regency's outstanding series A preferred units were converted into corresponding newly issued ETP Series A Preferred Units (the "Preferred Units") on a one-for-one basis. If outstanding, the Preferred Units are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon and are reflected as long-term liabilities in our consolidated balance sheets. The Preferred Units are entitled to a preferential quarterly cash distribution of $0.445 per Preferred Unit if outstanding on the record dates of the Partnership's common unit distributions. Holders of the Preferred Units can elect to convert the ETP Preferred Units to ETP Common Units at any time in accordance with ETP's partnership agreement. The number of common units issuable upon conversion of the Preferred Units is equal to the issue price of $18.30, plus all accrued but unpaid distributions and interest thereon, divided by the conversion price of $44.37. The Preferred Units were convertible to approximately 0.9 million ETP common units as of June 30, 2015.

8. 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.

9. 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.

Class H Units and Class I Units

In March 2015, ETE transferred 30.8 million Partnership common units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership 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. In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to the Partnership. These IDR subsidies, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

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 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.

During the six months ended June 30, 2015, the Partnership received proceeds of $569 million, net of commissions of $6 million, from the issuance of common units pursuant to equity distribution agreements, which were used for general partnership purposes. As of June 30, 2015, $832 million of the Partnership's common units remained available to be issued under an equity distribution agreement.

Equity Incentive Plan Activity

As discussed in Note 10, 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.

During the six months ended June 30, 2015, distributions of $155 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 2.8 million common units. As of June 30, 2015, a total of 4.5 million common units remain available to be issued under the existing registration statement in connection with the Distribution Reinvestment Plan.

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.

Bakken Transaction

In March 2015, ETE transferred 30.8 million Partnership common units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership 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. In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to the Partnership. These IDR subsidies, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

In connection with the transaction, ETP also issued 100 Class I Units. The Class I Units are 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."

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.

During the six months ended June 30, 2015, Sunoco Logistics received proceeds of $385 million, net of commissions of $4 million, from the issuance of common units pursuant to the equity distribution. The proceeds were used for general partnership purposes.

Additionally, Sunoco Logistics completed a public offering of 13.5 million common units for net proceeds of $547 million in March 2015. The net proceeds were used to repay outstanding borrowings under the $2.5 billion Sunoco Logistics Credit Facility and for general partnership purposes. In April 2015, an additional 2.0 million common units were issued for net proceeds of $82 million related to the exercise of an option in connection with the March 2015 offering.

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.

In July 2015, Sunoco LP completed an offering of 5.5 million Sunoco LP common units for net proceeds of $213 million. The net proceeds from the offering were used to repay outstanding balances under the Sunoco LP revolving credit facility.

Quarterly Distributions of Available Cash

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

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

Distributions declared during the periods presented 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
March 31, 2015	May 8, 2015	May 15, 2015	1.0150
June 30, 2015	August 6, 2015	August 14, 2015	1.0350

ETE agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units. The relinquishments subsequent to the Regency Merger were as follows:

	Total Year
2015 (for quarters ending subsequent to the Regency Merger on April 30, 2015)	$ 56
2016	137
2017	128
2018	105
2019	95

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
March 31, 2015	May 11, 2015	May 15, 2015	0.4190
June 30, 2015	August 10, 2015	August 14, 2015	0.4380

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
March 31, 2015	May 19, 2015	May 29, 2015	0.6450
June 30, 2015	August 18, 2015	August 28, 2015	0.6934

Predecessor Equity Issuances

The following table summarizes Regency's public offerings of Regency Common Units during the periods presented:

Date	Number of Regency Common Units	Price per Regency Unit	Net Proceeds
March 2012	12.7	$ 24.47	$ 297

Proceeds were used to repay amounts outstanding under the Regency Credit Facility and/or fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

Regency issued 4.0 million, 140.4 million and 8.2 million Regency Common Units in connection with the Hoover, PVR and Eagle Rock Midstream acquisitions, respectively.

In June 2014, Regency sold 14.4 million Regency Common Units to a wholly-owned subsidiary of ETE for approximately $400 million. Proceeds from the issuance were used to pay down borrowings on the Regency Credit Facility, to redeem certain Regency senior notes and for general partnership purposes. In July 2014, Regency sold an additional 16.5 million Regency Common Units to a wholly-owned subsidiary of ETE in connection with the Eagle Rock Midstream Acquisition for approximately $400 million. Proceeds from the issuance were used to fund a portion of the cash consideration paid to Eagle Rock in connection with the Eagle Rock Midstream Acquisition.

Regency's Equity Distribution Program

From time to time, Regency sold Regency Common Units through an equity distribution agreement. Such sales of Regency 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 June 2012, Regency entered into an equity distribution agreement with Citigroup Global Markets Inc. under which Regency may offer and sell Regency Common Units, representing limited partner interests, having an aggregate offering price of up to $200 million from time to time through Citi, as sales agent for Regency. For the years ended December 31, 2014 and 2013, Regency received net proceeds of $34 million and $149 million, respectively, from Regency Common Units issued pursuant to this equity distribution agreement. No amounts remain available to be issued under this agreement and it is no longer effective.

In May 2014, Regency entered into an equity distribution agreement with a group of banks and investment companies under which Regency may offer and sell Regency Common Units, representing limited partner interests, for an aggregate offering price of up to $400 million, from time to time through this group of institutions, as sales agent for Regency. For the year ended December 31, 2014, Regency received net proceeds of $395 million from Regency Common Units issued pursuant to this equity distribution agreement. No amounts remain available to be issued under this agreement and it is no longer effective.

In January 2015, Regency entered into an equity distribution agreement with a group of banks and investment companies (the "Managers") under which Regency may offer and sell Regency Common Units for an aggregate offering price of up to $1 billion, from time to time through the Managers, as sales agent for Regency. Regency used the net proceeds from the sale of Regency Common Units for general partnership purposes. The equity distribution agreement was terminated as a result of the Regency Merger.

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

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)

10. 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.

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.

Regency Unit-Based Compensation Plans

Regency had the following awards outstanding as of December 31, 2014:

- 107,650 Regency Common Unit options, all of which are exercisable, with a weighted average exercise price of $22.68 per unit option; and
- 2,167,719 Regency Phantom Units, with a weighted average grant date fair value of $24.31 per Phantom Unit.

Regency began granting cash restricted units in 2014. These awards are service condition (time-based) grants 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 Regency Common Unit upon vesting. Regency had 379,328 cash restricted units outstanding at December 31, 2014.

All of Regency's outstanding phantom units and cash restricted units were vested or converted to ETP restricted units and ETP cash restricted units, respectively, in connection with the Regency Merger.

11. 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	86	(2)	4
Total	407	49	1
Deferred expense (benefit):			
Federal	(50)	(6)	45
State	1	54	17
Total	(49)	48	62
Total income tax expense from continuing operations	$ 358	$ 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	45	54	31	5	36
Premium on debt retirement	(10)	—	(10)	—	—	—
Foreign	(8)	—	(8)	—	—	—
Other	—	—	—	(13)	(1)	(14)
Income tax from continuing operations	$ 313	$ 45	$ 358	$ 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.

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	$ (1,506)	$ (1,544)
Inventory	(153)	(302)
Investment in unconsolidated affiliates	(2,528)	(2,244)
Trademarks	(355)	(180)
Other	(32)	(45)
Total deferred income tax liabilities	(4,574)	(4,315)
Net deferred income tax liability	(4,331)	(3,903)
Less: current portion of deferred income tax liabilities, net	(85)	(119)
Accumulated deferred income taxes	$ (4,246)	$ (3,784)

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	$ (3,903)	$ (3,628)
Susser acquisition	(488)	—
SUGS Contribution to Regency	—	(115)
Tax provision (including discontinued operations)	60	(111)
Other	—	(49)
Net deferred income tax liability	$ (4,331)	$ (3,903)

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.

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. As of December 31, 2014, the IRS has proposed only one adjustment for the years under examination.

On July 23, 2015, we reached a final settlement with the Internal Revenue Service ("IRS") with regards to the IRS examination of Southern Union's tax years 2004 through 2009. For the 2006 tax year, the IRS had challenged $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of Southern Union's distribution operations and its gathering and processing operations. The terms of the settlement specify that our position with regards to the deferred gain on the like kind exchange was materially correct and as a result, we will receive refunds totaling approximately $6 million for the periods under examination.

During the three months ended June 30, 2015, Sunoco, Inc. filed a petition for refund with the United States Court of Federal Claims in response to a notice of disallowance denying previously filed refund claims related to certain government incentive payments. Also, during the same period, Sunoco, Inc. filed amended state income tax returns in material jurisdictions based on the Federal claim. The state refund claim is $87 million ($57 million after Federal taxes). Consistent with treatment of Federal claims, Sunoco, Inc. has established a reserve for the full amount of the increase due to the uncertain nature of the claims.

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.

12. 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.

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.

On April 30, 2015, in connection with the Regency Merger, ETP entered into various supplemental indentures pursuant to which ETP had agreed to fully and unconditionally guarantee all payment obligations of Regency for all of its outstanding senior notes.

On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it has agreed to become a co-obligor with respect to the payment obligations thereunder. Accordingly, pursuant to the terms of the senior notes, Panhandle's obligations under the Panhandle Guarantee have been released.

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.

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)]	$ 159	$ 151	$ 60
Less: Sublease rental income	(26)	(24)	(4)
Rental expense, net	$ 133	$ 127	$ 56

(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	$ 151
2016	129
2017	118
2018	108
2019	102
Thereafter	829
Future minimum lease commitments	1,437
Less: Sublease rental income	(34)
Net future minimum lease commitments	$ 1,403

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 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.

Regency Merger Litigation

Following the January 26, 2015 announcement of the definitive merger agreement with Regency, purported Regency unitholders filed lawsuits in state and federal courts in Dallas, Texas and Delaware state court asserting claims relating to the proposed transaction.

On February 3, 2015, William Engel and Enno Seago, purported Regency unitholders, filed a class action petition on behalf of Regency's common unitholders and a derivative suit on behalf of Regency in the 162nd Judicial District Court of Dallas County, Texas (the "Engel Lawsuit"). The lawsuit names as defendants the Regency General Partner, the members of the Regency General Partner's board of directors, ETP, ETP GP, ETE, and, as a nominal party, Regency. The Engel Lawsuit alleges that (1) the Regency General Partner's directors breached duties to Regency and the Regency's unitholders by employing a conflicted and unfair process and failing to maximize the merger consideration; (2) the Regency General Partner's directors breached the implied covenant of good faith and fair dealing by engaging in a flawed merger process; and (3) the non-director defendants aided and abetted in these claimed breaches. The plaintiffs seek an injunction preventing the defendants from closing the proposed transaction or an order rescinding the transaction if it has already been completed. The plaintiffs also seek money damages and court costs, including attorney's fees.

On February 9, 2015, Stuart Yeager, a purported Regency unitholder, filed a class action petition on behalf of the Regency's common unitholders and a derivative suit on behalf of Regency in the 134th Judicial District Court of Dallas County, Texas (the "Yeager Lawsuit"). The allegations, claims, and relief sought in the Yeager Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 10, 2015, Lucien Coggia a purported Regency unitholder, filed a class action petition on behalf of Regency's common unitholders and a derivative suit on behalf of Regency in the 192nd Judicial District Court of Dallas County, Texas (the "Coggia Lawsuit"). The allegations, claims, and relief sought in the Coggia Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 3, 2015, Linda Blankman, a purported Regency unitholder, filed a class action complaint on behalf of the Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Blankman Lawsuit"). The allegations and claims in the Blankman Lawsuit are similar to those in the Engel Lawsuit. However, the Blankman Lawsuit does not allege any derivative claims and includes Regency as a defendant rather than a nominal party. The lawsuit also omits one of the Regency General Partner's directors, Richard Brannon, who was named in the Engel Lawsuit. The

Blankman Lawsuit alleges that the Regency General Partner's directors breached their fiduciary duties to the unitholders by failing to maximize the value of Regency, failing to properly value Regency, and ignoring conflicts of interest. The plaintiff also asserts a claim against the non-director defendants for aiding and abetting the directors' alleged breach of fiduciary duty. The Blankman Lawsuit seeks the same relief that the plaintiffs seek in the Engel Lawsuit.

On February 6, 2015, Edwin Bazini, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Bazini Lawsuit"). The allegations, claims, and relief sought in the Bazini Lawsuit are nearly identical to those in the Blankman Lawsuit. On March 27, 2015, Plaintiff Bazini filed an amended complaint asserting additional claims under Sections 14(a) and 20(a) of the Securities Exchange Act of 1934.

On February 11, 2015, Mark Hinnau, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Hinnau Lawsuit"). The allegations, claims, and relief sought in the Hinnau Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Stephen Weaver, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Weaver Lawsuit"). The allegations, claims, and relief sought in the Weaver Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Adrian Dieckman, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Dieckman Lawsuit"). The allegations, claims, and relief sought in the Dieckman Lawsuit are similar to those in the Blankman Lawsuit, except that the Dieckman Lawsuit does not assert an aiding and abetting claim.

On February 13, 2015, Irwin Berlin, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Berlin Lawsuit"). The allegations, claims, and relief sought in the Berlin Lawsuit are similar to those in the Blankman Lawsuit.

On March 13, 2015, the Court in the 95th Judicial District Court of Dallas County, Texas transferred and consolidated the Yeager and Coggia Lawsuits into the Engel Lawsuit and captioned the consolidated lawsuit as *Engel v. Regency GP, LP, et al*. (the "Consolidated State Lawsuit").

On March 30, 2015, Leonard Cooperman, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the United States District Court for the Northern District of Texas (the "Cooperman Lawsuit"). The allegations, claims, and relief sought in the Cooperman Lawsuit are similar to those in the Blankman Lawsuit.

On March 31, 2015, the Court in United States District Court for the Northern District of Texas consolidated the Blankman, Bazini, Hinnau, Weaver, Dieckman, and Berlin Lawsuits into a consolidated lawsuit captioned *Bazini v. Bradley, et al*. (the "Consolidated Federal Lawsuit"). On April 1, 2015, plaintiffs in the Consolidated Federal Lawsuit filed an Emergency Motion to Expedite Discovery. On April 9, 2015, by order of the Court, the parties submitted a joint submission wherein defendants opposed plaintiffs' request to expedite discovery. On April 17, 2015, the Court denied plaintiffs' motion to expedite discovery.

On June 10, 2015, Adrian Dieckman, a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the Court of Chancery of the State of Delaware (the "Dieckman DE Lawsuit"). The lawsuit alleges that the transaction did not comply with the Regency partnership agreement because the Conflicts Committee was not properly formed.

Each of these lawsuits is at a preliminary stage. ETP cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. ETP and the other defendants named in the lawsuits intend to defend vigorously against these and any other actions.

Litigation Relating to the PVR Merger

Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of these cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Eagle Rock Shareholder Litigation

Three putative class action lawsuits challenging the Eagle Rock Midstream Acquisition are currently pending in federal district court in Houston, Texas. All cases name Eagle Rock and its current directors, as well as the Partnership and a subsidiary, as defendants. One of the lawsuits also names additional Eagle Rock entities as defendants. Each of the lawsuits has been brought by a purported unitholder of Eagle Rock (collectively, the "Plaintiffs"), both individually and on behalf of a putative class consisting of public unitholders of Eagle Rock. The Plaintiffs in each case seek to rescind the transaction, claiming, among other things, that it yields inadequate consideration, was tainted by conflict and constitutes breaches of common law fiduciary duties or contractually imposed duties to the shareholders. Plaintiffs also seek monetary damages and attorneys' fees. Regency and its subsidiary are named as "aiders and abettors" of the allegedly wrongful actions of Eagle Rock and its board.

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 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.

Air Quality Control

SUGS is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the New Mexico Environmental Department

SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the compliance orders were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. SUGS has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. SUGS has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations 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.

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	$ 41	$ 47
Non-current	360	356
Total environmental liabilities	$ 401	$ 403

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 $48 million and $41 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.

13. 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 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.

ETP's Preferred Units (see Note 7) contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and ETP's call option. These embedded derivatives are accounted for using mark-to-market accounting. ETP does not expect the embedded derivatives to affect its cash flows.

Regency

Regency is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as market forces. Regency's profitability and cash flow are affected by the inherent volatility of these commodities. Regency manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas and the use of derivative contracts. In some cases, Regency may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk.

Marketing & Trading. Regency conducts natural gas marketing and trading activities through its Logistics and Trading subsidiary. Regency engages in activities intended to capitalize on favorable price differentials between various receipt and delivery locations. Regency enters into both financial derivatives and physical contracts. These financial derivatives, primarily basis swaps, are transacted: (i) to economically hedge subscribed capacity exposed to market rate fluctuations and (ii) to mitigate the price risk related to other purchase and sales of natural gas. By entering into a basis swap, one pricing index is exchanged for another, effectively locking in the margin between the natural gas purchase and sale by removing index spread risk on the combined physical and financial transaction. Changes in the fair value of these financial and physical contracts are recorded as adjustments to natural gas sales and realized (unrealized) gain (loss) from derivatives, as appropriate.

Through its natural gas marketing activity, Regency has credit exposure to additional counterparties. Regency minimizes the credit risk associated with natural gas marketing by limiting its exposure to any single counterparty and monitoring the creditworthiness of its counterparties on an ongoing basis. In addition, Regency's natural gas purchase and sale contracts, for certain counterparties, are subject to counterparty netting agreements governing settlement under such natural gas purchase and sales contracts, and when possible, Regency nets the open positions of each counterparty.

The following table details the outstanding commodity-related derivatives related to ETP's legacy operations and Regency's operations:

ETP Legacy Operations

	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.

Regency Operations

	December 31, 2014		December 31, 2013	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Non-Trading)				
Natural Gas (MMBtu) — Fixed Swaps/Futures	(25,525,000)	2015	(24,455,000)	2014-2015
Propane (Gallons) — Forwards/Swaps	(29,148,000)	2015	(52,122,000)	2014-2015
NGLs (Barrels) — Forwards/Swaps	(292,000)	2015	(438,000)	2014
WTI Crude Oil (Barrels) — Forwards/Swaps	(1,252,000)	2015-2016	(521,000)	2014

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.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2014	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 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	$ 2	$ —	$ (20)
	43	2	—	(20)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 617	$ 227	$ (577)	$ (209)
Commodity derivatives	107	43	(23)	(45)
Interest rate derivatives	3	47	(155)	(95)
Embedded derivatives in Regency Preferred Units	—	—	(16)	(19)
	727	317	(771)	(368)
Total derivatives	$ 770	$ 319	$ (771)	$ (388)

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	$ 42	$ (23)	$ (38)
Broker cleared derivative contracts	Other current assets	674	264	(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		87	50	(171)	(123)
Total derivatives		$ 770	$ 319	$ (771)	$ (388)

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

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

	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	199	(21)	26
Commodity contracts – Non-trading	Deferred gas purchases	—	(3)	(26)
Interest rate derivatives	Gains (losses) on interest rate derivatives	(157)	53	(19)
Embedded derivatives	Other income	3	6	14
Total		$ 39	$ 24	$ (12)

14. 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 and our subsidiaries made matching contributions of $59 million, $47 million and $30 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.

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)

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

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 as of December 31, 2014	Fair Value Measurements at December 31, 2014 Using Fair Value Hierarchy		
		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	$ —

(1) Primarily comprised of approximately 100% equities as of December 31, 2014.

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		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 as of December 31, 2014	Fair Value Measurements at December 31, 2014 Using Fair Value Hierarchy		
		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 as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		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.

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.

15. 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	$ 965	$ 1,442	$ 188

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
Dakota Access Pipeline	68	—
PES	6	7
FGT	9	29
ET Crude Oil	10	24
Lake Charles LNG	3	—
Other	32	39
Total accounts receivable from related companies:	$ 139	$ 117
Accounts payable to related companies:		
ETE	$ —	$ 10
FGT	2	8
Lake Charles LNG	2	—
Other	21	7
Total accounts payable to related companies:	$ 25	$ 25

16. 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, 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.

In connection with the Regency Merger, Regency’s operations were aggregated into ETP’s existing segments. Regency’s gathering and processing operations were aggregated into our midstream segment. Regency’s natural gas transportation operations were aggregated into our intrastate transportation and storage and interstate transportation and storage segments. Regency’s contract services and natural resources operations were aggregated into our all other segment. Additionally, in June 2015 Regency’s 30% equity interest in Lone Star was transferred to ETC OLP.

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	$ 2,645	$ 2,242	$ 2,010
Intersegment revenues	212	210	181
	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	4,770	3,220	2,869
Intersegment revenues	2,053	1,056	208
	6,823	4,276	3,077
Liquids transportation and services:			
Revenues from external customers	3,730	2,025	619
Intersegment revenues	181	101	31
	3,911	2,126	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	2,869	2,094	1,322
Intersegment revenues	462	503	440
	3,331	2,597	1,762
Eliminations	(3,094)	(2,076)	(940)
Total revenues	$ 55,475	$ 48,335	$ 16,964

	Years Ended December 31,		
	2014	2013	2012
Cost of products sold:			
Intrastate transportation and storage	$ 2,169	$ 1,737	$ 1,394
Midstream	4,893	3,130	2,120
Liquids transportation and services	3,166	1,654	361
Investment in Sunoco Logistics	17,110	15,574	2,885
Retail marketing	21,154	20,150	5,757
All other	2,975	2,337	1,511
Eliminations	(3,078)	(2,028)	(940)
Total cost of products sold	$ 48,389	$ 42,554	$ 13,088

	Years Ended December 31,		
	2014	2013	2012
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 125	$ 122	$ 122
Interstate transportation and storage	203	244	209
Midstream	569	335	277
Liquids transportation and services	113	91	53
Investment in Sunoco Logistics	296	265	63
Retail marketing	189	114	28
All other	174	125	106
Total depreciation and amortization	$ 1,669	$ 1,296	$ 858

	Years Ended December 31,		
	2014	2013	2012
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ 27	$ 30	$ 33
Interstate transportation and storage	196	182	162
Midstream	10	1	(10)
Liquids transportation and services	(3)	(2)	2
Investment in Sunoco Logistics	23	18	5
Retail marketing	2	2	1
All other	77	5	19
Total equity in earnings of unconsolidated affiliates	$ 332	$ 236	$ 212

	Years Ended December 31,		
	2014	2013	2012
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 559	$ 521	$ 667
Interstate transportation and storage	1,212	1,368	1,117
Midstream	1,349	766	613
Liquids transportation and services	591	350	209
Investment in Sunoco Logistics	971	871	219
Retail marketing	731	325	109
All other	297	203	205
Total Segment Adjusted EBITDA	5,710	4,404	3,139
Depreciation, depletion and amortization	(1,669)	(1,296)	(858)
Interest expense, net of interest capitalized	(1,165)	(1,013)	(788)
Gain on deconsolidation of Propane Business	—	—	1,057
Gain on sale of AmeriGas common units	177	87	—
Goodwill impairment	(370)	(689)	—
Gains (losses) on interest rate derivatives	(157)	44	(4)
Non-cash unit-based compensation expense	(68)	(54)	(47)
Unrealized gains (losses) on commodity risk management activities	112	42	2
Inventory valuation adjustments	(473)	3	(75)
Loss on extinguishment of debt	(25)	(7)	(124)
Non-operating environmental remediation	—	(168)	—
Adjusted EBITDA related to discontinued operations	(27)	(76)	(99)
Adjusted EBITDA related to unconsolidated affiliates	(748)	(722)	(646)
Equity in earnings of unconsolidated affiliates	332	236	212
Other, net	(36)	19	48
Income from continuing operations before income tax expense	$ 1,593	$ 810	$ 1,817

	December 31,		
	2014	2013	2012
Assets:			
Intrastate transportation and storage	$ 4,984	$ 5,048	$ 5,340
Interstate transportation and storage	10,779	11,537	12,376
Midstream	15,562	7,847	7,189
Liquids transportation and services	4,568	4,321	3,742
Investment in Sunoco Logistics	13,619	11,650	10,291
Retail marketing	8,930	3,936	3,926
All other	4,232	5,561	5,530
Total assets	$ 62,674	$ 49,900	$ 48,394

	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	1,298	1,114	1,633
Liquids transportation and services	427	448	1,306
Investment in Sunoco Logistics	2,510	1,018	139
Retail marketing	259	176	58
All other	420	372	227
Total additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs	$ 5,494	$ 3,327	$ 3,533

	December 31,		
	2014	2013	2012
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 423	$ 443	$ 652
Interstate transportation and storage	2,649	2,588	2,723
Midstream	138	36	36
Liquids transportation and services	31	29	29
Investment in Sunoco Logistics	226	125	118
Retail marketing	19	22	21
All other	274	807	1,189
Total advances to and investments in unconsolidated affiliates	$ 3,760	$ 4,050	$ 4,768

17. 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	$ 13,027	$ 14,088	$ 14,933	$ 13,427	$ 55,475
Gross profit	1,585	1,737	1,919	1,845	7,086
Operating income	706	769	809	159	2,443
Net income	483	548	513	(245)	1,299
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

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2013:					
Revenues	$ 11,179	$ 12,063	$ 12,486	$ 12,607	$ 48,335
Gross profit	1,372	1,497	1,422	1,490	5,781
Operating income (loss)	541	671	545	(138)	1,619
Net income (loss)	402	411	415	(482)	746
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 and Regency's recognition of a goodwill impairment of $370 million. 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.

Exhibit 99.2

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Sunoco Partners LLC and Limited Partners of Sunoco Logistics Partners, L.P.

We have audited the accompanying consolidated statements of comprehensive income, equity, and cash flows of Sunoco Logistics Partners L.P. (the "Partnership") for the period from October 5, 2012 to December 31, 2012 (successor) and the period from January 1, 2012 to October 4, 2012 (predecessor). These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Sunoco Logistics Partners L.P. for the period from October 5, 2012 to December 31, 2012 (successor) and the period from January 1, 2012 to October 4, 2012 (predecessor), in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
March 1, 2013

Exhibit 99.3

REPORT OF INDEPENDENT AUDITORS

The Shareholders of Susser Holdings Corporation

We have audited the accompanying consolidated financial statements of Susser Holdings Corporation (the Company) which comprise the consolidated balance sheets as of December 31, 2014 and December 29, 2013, and the related consolidated statements of operations and comprehensive income, shareholders' equity, and cash flows for the periods from September 1, 2014 through December 31, 2014 and December 30, 2013 through August 31, 2014, and the years ended December 29, 2013 and December 30, 2012 (not presented separately herein).

Management’s Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor’s Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risk of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors considers internal control relevant to the entity’s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity’s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Susser Holdings Corporation at December 31, 2014 and December 29, 2013, and the consolidated results of its operations and its cash flows for the periods from September 1, 2014 through December 31, 2014 and December 30, 2013 through August 31, 2014, and the years ended December 29, 2013 and December 31, 2012, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
February 28, 2015, except for Note 2, as to which the date is April 30, 2015

Exhibit 99.4

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Sunoco LP and
Unitholders of Sunoco LP

We have audited the accompanying consolidated balance sheets of Sunoco LP (formerly Susser Petroleum Partners LP) as of December 31, 2014 and 2013, and the related consolidated statements of operations and comprehensive income, partners ' equity, and cash flows for the periods from September 1, 2014 through December 31, 2014 and January 1, 2014 through August 31, 2014, and the years ended December 31, 2013 and 2012 (not presented separately herein). These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Sunoco LP at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for the periods from September 1, 2014 through December 31, 2014 and January 1, 2014 through August 31, 2014, and the years ended December 31, 2013 and 2012, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2015