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): July 10, 2014

ENERGY TRANSFER EQUITY, L.P.

(Exact name of Registrant as specified in its charter)

Delaware	001-32740	30-0108820
(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 certain retrospective revisions for changes in reportable segments that have been made to the consolidated financial statements of Energy Transfer Equity, L.P. ("ETE" or the "Partnership") that were previously filed with the Securities and Exchange Commission by the Partnership on February 27, 2014 as Items 1, 7 and 8 to its Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 Form 10-K"). ETE began reporting comparative results using the revised segment presentation effective with the filing of its Quarterly Report on Form 10-Q for the period ended March 31, 2014.

As a result of the transaction that was consummated between ETE and Energy Transfer Partners, L.P. ("ETP") on February 19, 2014, ETE's reportable segments in its consolidated financial statements were re-evaluated. Beginning with ETE's Form 10-Q for the period ended March 31, 2014, ETE's reportable segments now consist of the following:

- Investment in ETP, including the consolidated operations of ETP;

- Investment in Regency, including the consolidated operations of Regency Energy Partners LP ("Regency");

- Investment in Trunkline LNG, including the operations of Trunkline LNG Company, LLC ("Trunkline LNG"); and

- Corporate and Other.

In order to preserve the nature and character of the disclosures set forth in the 2013 Form 10-K, the items included in this Form 8-K have been updated solely for matters relating specifically to the realignment of ETE's reportable segments, as described above. No attempt has been made in the audited financial statements included in Exhibit 99.1 in this Form 8-K, and it should not be read, to modify or update other disclosures as presented in the 2013 Form 10-K to reflect events or occurrences after the date of the filing of the 2013 Form 10-K, February 27, 2014. Therefore, this Form 8-K should be read in conjunction with the Form 10-K, and filings made by ETE with the SEC subsequent to the filing of the Form 10-K, including ETE's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014 filed on May 8, 2014.

Item 9.01 of this Current Report on Form 8-K revises certain information contained in ETE's 2013 Form 10-K to reflect these changes in reportable segments. In particular, Exhibit 99.1 contains a revised description of the ETE's business segments, 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
99.1	Revised Energy Transfer Equity, L.P. description of the business, financial statements as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, and Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.2	Report of Ernst & Young LLP
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 Equity, L.P.

By: LE GP, LLC,
its general partner

Date: July 10, 2014

/s/ Jamie Welch
Jamie Welch
Group Chief Financial Officer

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, except for Note 15 as to which the date is July 10, 2014, with respect to the consolidated financial statements included in this Current Report of Energy Transfer Equity, L.P. on Form 8-K. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas

July 10, 2014

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. 333-192327 of Energy Transfer Equity, L.P.

(2) Registration Statement on Form S-3 No. 333-146300 of Energy Transfer Equity, L.P.

(3) Registration Statement on Form S-8 No. 333-146298 pertaining to the Employees' Savings Plan of Energy Transfer Equity, L.P.

of our report dated March 1, 2013, with respect to the consolidated financial statements of Sunoco Logistics Partners L.P., included in this Current Report (Form 8-K) of Energy Transfer Equity, L.P.

/s/Ernst & Young LLP

Philadelphia, Pennsylvania

July 10, 2014

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Equity, L.P. (the “Partnership” or “ETE”) 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,” “project,” “expect,” “plan,” “goal,” “forecast,” “estimate,” “intend,” “continue,” “could,” “believe,” “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, estimated, projected, forecasted, expressed or expected 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 1.A Risk Factors” included in this annual report.

Definitions

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

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
AROs	asset retirement obligations
Bbls	barrels
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy content
Canyon	ETC Canyon Pipeline, LLC
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
Citrus	Citrus Corp., which owns 100% of FGT
CrossCountry	CrossCountry Energy, LLC
CFTC	Commodities Futures Trading Commission
DOT	U.S. Department of Transportation
Eagle Rock	Eagle Rock Energy Partners, LP
Enterprise	Enterprise Products Partners L.P., together with its subsidiaries
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
ETG	Energy Transfer Group, L.L.C.
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP	Energy Transfer Partners, L.P.

ETP Credit Facility	ETP's revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FDOT/FTE	Florida Department of Transportation, Florida's Turnpike Enterprise
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC, which owns a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula
GAAP	accounting principles generally accepted in the United States of America
General Partner	LE GP, LLC, the general partner of ETE
HPC	RIGS Haynesville Partnership Co.
Holdco	ETP Holdco Corporation
HOLP	Heritage Operating, L.P.
Hoover Energy	Hoover Energy Partners, LP
IDRs	incentive distribution rights
LDH	LDH Energy Asset Holdings LLC, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC (subsequently renamed Castleton Commodities International, LLC)
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
LNG Holdings	Trunkline LNG Holdings, LLC
LPG	liquefied petroleum gas
Lone Star	Lone Star NGL LLC
MACS	Mid-Atlantic Convenience Stores
MEP	Midcontinent Express Pipeline LLC
MGE	Missouri Gas Energy
MGP	manufactured gas plant
MMBtu	million British thermal units
MMcf	million cubic feet
NGA	Natural Gas Act of 1938
NGPA	Natural Gas Policy Act of 1978
NEG	New England Gas Company
NGL	natural gas liquid, such as propane, butane and natural gasoline
NMED	New Mexico Environmental Department
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OSHA	Federal Occupational Safety and Health Act

Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCB	polychlorinated biphenyl
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC, a wholly-owned subsidiary of Southern Union, which owned the general partner and 100% of the limited partner interests in PEPL
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
PVR	PVR Partners, L.P.
RIGS	Regency Intrastate Gas System
RGS	Regency Gas Services, a wholly-owned subsidiary of Regency
Preferred Units	ETE’s Series A Convertible Preferred Units
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Regency GP	Regency GP LP, the general partner of Regency
Regency LLC	Regency GP LLC, the general partner of Regency GP
Regency Preferred Units	Regency’s Series A Convertible Preferred Units, the Preferred Units of a Subsidiary
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC
SUGS	Southern Union Gas Services
Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
TCEQ	Texas Commission on Environmental Quality
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC
Trunkline LNG	Trunkline LNG Company, LLC
WTI	West Texas Intermediate Crude

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries’ results of operations and for unconsolidated affiliates based on the Partnership’s proportionate ownership.

BUSINESS

Overview

We were formed in September 2002 and completed our initial public offering in February 2006. We are a Delaware limited partnership with common units publicly traded on the NYSE under the ticker symbol "ETE."

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ETE" mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, ETP GP, ETP LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Sunoco Logistics and Holdco. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

In January 2014, the Partnership completed a two-for-one split of its outstanding common units. All references to units and per unit amounts in this document have been adjusted to reflect the effect of the unit split for all periods presented.

On March 26, 2012, we acquired all of the outstanding shares of Southern Union and contributed our ownership in Southern Union for a 60% interest in Holdco at the time of ETP's acquisition of Sunoco on October 5, 2012. On April 30, 2013, ETP acquired ETE's 60% interest in Holdco.

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency, both of which are publicly traded master limited partnerships engaged in diversified energy-related services.

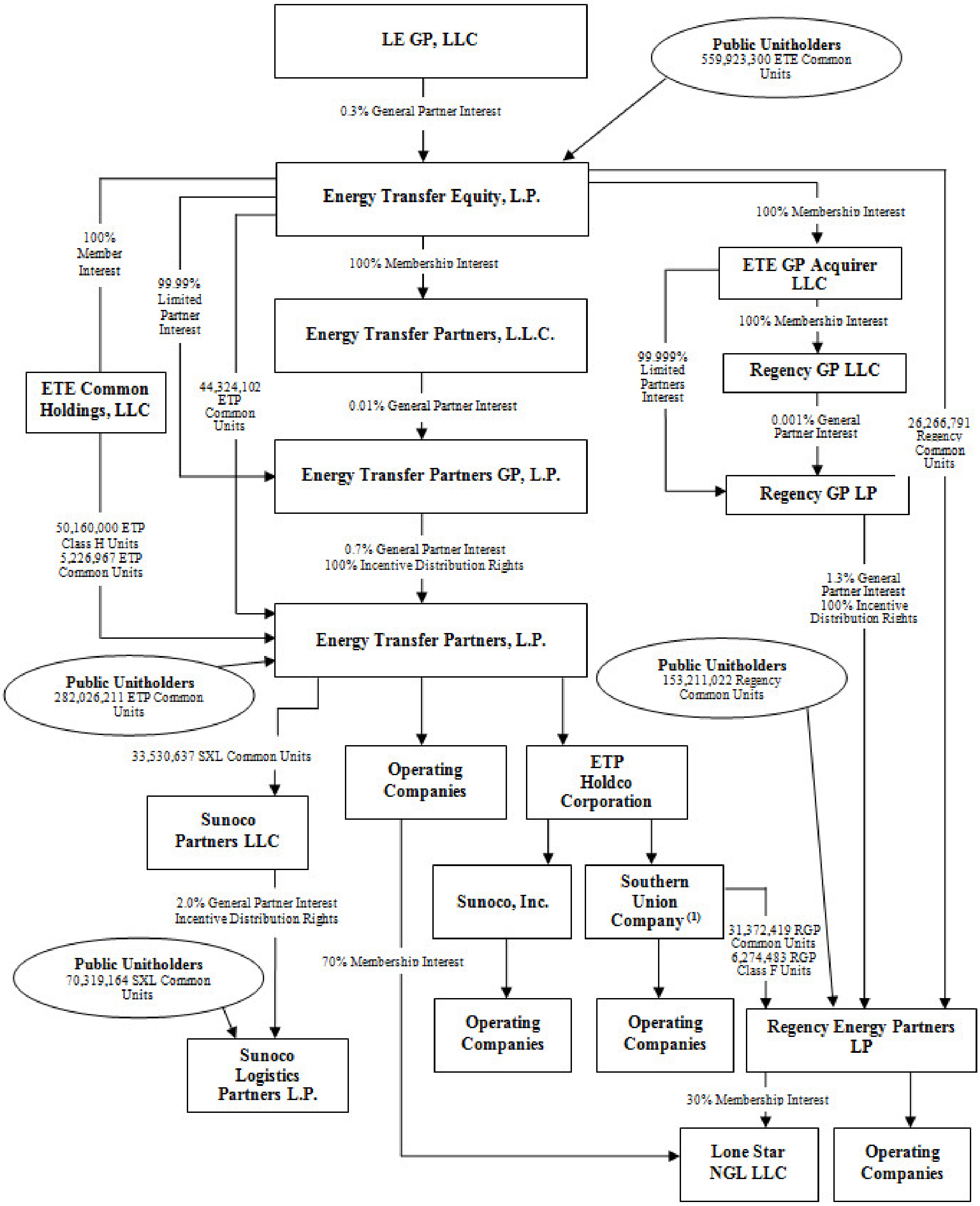
At December 31, 2013, our interests in ETP and Regency consisted of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49,551,069	26,266,791
ETP Class H units	50,160,000	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31,372,419
Regency Class F units	—	6,274,483

The Parent Company's primary cash requirements are for distributions to its partners, general and administrative expenses, debt service requirements and at ETE's election, capital contributions to ETP and Regency in respect of ETE's general partner interests in ETP and Regency. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of subsidiaries.

Organizational Structure

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



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

Strategic Transactions

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

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

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

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

- On July 12, 2013, ETP received $346 million in net proceeds from the sale of 7.5 million of its AmeriGas common units, which were received in connection with the Partnership's contribution of its retail propane operations to AmeriGas in January 2012. In January 2014, ETP sold 9.2 million AmeriGas common units for net proceeds of $381 million.

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

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

- On October 31, 2013, ETP and ETE exchanged 50.2 million ETP Common Units, owned by ETE, for newly issued Class H Units by ETP that track 50% of the underlying economics of the general partner interest and the IDRs of Sunoco Logistics.

- In December 2013, ETE completed a tender offer for a portion of its outstanding 7.50% Senior Notes due 2020. In conjunction with the tender offer, ETE completed a comprehensive refinancing of its existing debt, which included the public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024, a new $1 billion term loan facility, and a new $600 million revolving credit facility. In February 2014, ETE increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

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

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

- In October 2013, Regency entered into a merger agreement with PVR pursuant to which Regency intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The PVR Acquisition is expected to enhance our 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. The PVR Acquisition is expected to close in late March 2014, subject to receipt of the affirmative vote of a majority of the PVR common units outstanding at a meeting scheduled to be held on March 20, 2014 and subject to the satisfaction of other customary closing conditions.

- In December, 2013, Regency entered into an agreement to purchase Eagle Rock's midstream business for $1.3 billion. This acquisition is expected to complement Regency's core gathering and processing business and further diversify Regency's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014.

- On February 3, 2014, Regency completed its acquisition of the subsidiaries (the "acquired Hoover entities") of Hoover Energy that are engaged in crude oil gathering, transportation and terminalling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in West Texas. The consideration paid by Regency in exchange for the acquired Hoover entities was valued at $282 million (subject to customary post-closing adjustments) and consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy and (ii) $184 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. Regency financed the cash portion of the purchase price through borrowings under its revolving credit facility.

Business Strategy

Our primary business objective is to increase cash available for distributions to our unitholders by actively assisting our subsidiaries in executing their business strategies by assisting in identifying, evaluating and pursuing strategic acquisitions and growth opportunities. In general, we expect that we will allow our subsidiaries the first opportunity to pursue any acquisition or internal growth project that may be presented to us which may be within the scope our their operations or business strategies. In the future, we may also support the growth of our subsidiaries through the use of our capital resources which could involve loans, capital contributions or other forms of credit support to our subsidiaries. This funding could be used for the acquisition by one of our subsidiaries of a business or asset or for an internal growth project. In addition, the availability of this capital could assist our subsidiaries in arranging financing for a project, reducing its financing costs or otherwise supporting a merger or acquisition transaction.

Segment Overview

As a result of the acquisition of Trunkline LNG in February 2014, our reportable segments were re-evaluated and currently reflect the following reportable segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Regency, including the consolidated operations of Regency;
- Investment in Trunkline LNG, including the consolidated operations of Trunkline LNG; and
- Corporate and Other, including the following:
  - activities of the Parent Company; and
  - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

The businesses within these segments are described below. See Note 15 to our consolidated financial statements for additional financial information about our reportable segments.

Investment in ETP

ETP's operations include the following:

Intrastate Transportation and Storage Operations

ETP's 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 its intrastate transportation and storage Operations, ETP owns and operates approximately 7,800 miles of natural gas transportation pipelines with approximately 14.0 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas.

ETP 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. In addition, ETP's intrastate transportation and storage operations generate revenues from fees charged for storing customers' working natural gas in ETP's storage facilities and from margin from managing natural gas for its own account.

Interstate Transportation and Storage Operations

ETP's 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 its interstate transportation and storage operations, ETP directly owns and operates approximately 12,800 miles of interstate natural gas pipeline with approximately 11.3 Bcf/d of transportation capacity and has a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline. ETP also owns a 50% interest in Citrus which owns 100% of FGT, an approximately 5,400 mile pipeline system that extends from South Texas through the Gulf Coast to South Florida.

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

Midstream Operations

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.

Through ETP's midstream operations, ETP owns and operates approximately 6,700 miles of in service natural gas and NGL gathering pipelines with approximately 6.0 Bcf/d of gathering capacity, 5 natural gas processing plants, 15 natural gas treating facilities and 3 natural gas conditioning facilities. ETP's midstream operations focus 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 ETP's midstream assets are integrated with its intrastate transportation and storage assets.

NGL Transportation and Services Operations

NGL transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities. NGL storage facilities are used for the storage of mixed NGLs, NGL products and petrochemical products owned by third-parties in storage tanks and underground wells, which allow for the injection and withdrawal of such products at various times of the year to meet demand cycles. NGL fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.

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

ETP's Investment in Sunoco Logistics

ETP's interests in Sunoco Logistics consist of a 2% general partner interest, 100% of the IDRs and 33.5 million Sunoco Logistics common units representing 32% of the limited partner interests in Sunoco Logistics as of December 31, 2013. Because ETP controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into the Partnership.

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

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

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

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

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

Retail Marketing Operations

ETP's retail marketing and wholesale distribution business operations consists of the following:

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

ETP's All Other Operations and Investments

ETP's other operations and investments include the following:

- ETP owns 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP's other operations.
- ETP owns 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.
- ETP owns common units in AmeriGas, a publicly traded company engaged in retail propane marketing. ETP acquired this interest when it contributed its retail propane operations to AmeriGas in January 2012. As of December 31, 2013, ETP owned common units representing approximately 24% of AmeriGas' outstanding common units and, following a sale of a portion of these units in a public offering in January 2014, ETP owns 12.9 million AmeriGas common units representing approximately 14% of AmeriGas' outstanding common units.
- Southern Union previously had operations providing local distribution of natural gas in Missouri and Massachusetts. The operations were conducted through the Southern Union's operating divisions: MGE and NEG. Both of these operating divisions were disposed of in 2013.
- Sunoco owns an approximate 33% non-operating interest in PES, a refining joint venture with The Carlyle Group, L.P. ("The Carlyle Group"), which owns a refinery in Philadelphia. Sunoco has a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.
- ETP owns an investment in Regency related to the Regency common and Class F units received by Southern Union in exchange of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013.
- ETP conducts marketing operations in which it markets the natural gas that flows through its gathering and intrastate transportation assets, referred to as on-system gas.

Investment in Regency

Regency's operations include the following:

Gathering and Processing Operations

Regency provides "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems, and the gathering of oil (crude and/or condensate, a lighter oil) received from producers. These operations also include Edwards Lime Gathering LLC and Regency's 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. Regency completed its acquisition of SUGS on April 30, 2013 which was a transaction between entities under common control. Therefore, Regency's Gathering and Processing operations amounts have been retrospectively adjusted to reflect the SUGS Acquisition beginning March 26, 2012, the date upon which common control began.

Natural Gas Transportation Operations

Regency owns 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, and a 50% membership interest in MEP, which owns a 500-mile interstate natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. These operations also include Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

NGL Services Operations

Regency owns a 30% membership interest in Lone Star with ETP owning the remaining 70% membership interest.

Contract Services Operations

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

Investment in Trunkline LNG

Trunkline LNG operates a LNG import terminal, which has approximately 9.0 bcf of above ground LNG storage capacity and re-gasification facilities on Louisiana's Gulf Coast near Lake Charles, Louisiana. Trunkline LNG is engaged in interstate commerce and is subject to the rules, regulations and accounting requirements of the FERC.

Asset Overview

Investment in ETP

The following details the assets in ETP's operations:

Intrastate Transportation and Storage

The following details pipelines and storage facilities in ETP's intrastate transportation and storage operations:

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 ETP's 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 ETP's 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 ETP's storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2015.

In addition, the ET Fuel System is integrated with ETP's Godley processing plant which gives ETP 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 ETP's Southeast Texas System and is an important component to maximizing ETP's 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 ETP to bypass ETP's processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

HPL System

- Capacity of 5.3 Bcf/d
- Approximately 3,900 miles of natural gas pipeline
- Bammel storage facility with 62 Bcf of total working gas capacity

The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The HPL System is well situated to gather and transport gas in many of the major gas producing areas in Texas including the strong presence in the key Houston Ship Channel and Katy Hub markets, allowing ETP 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 ETP's Bammel storage facility.

The Bammel storage facility has a total working gas capacity of approximately 62 Bcf, a peak withdrawal rate of 1.3 Bcf/d and a peak injection rate of 0.6 Bcf/d. The Bammel storage facility is located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers. As of December 31, 2013, ETP had approximately 7.2 Bcf committed under fee-based arrangements with third parties and approximately 45.8 Bcf stored in the facility for ETP's own account.

ETP is currently converting approximately 84 miles of pipeline from the HPL System to crude service. This project is expected to be completed in 2014.

East Texas Pipeline

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

The East Texas pipeline connects three treating facilities, one of which ETP owns, with ETP's Southeast Texas System. The East Texas pipeline was the first phase of a multi-phased project that increased service to producers in East and North Central Texas and provided access to the Katy Hub. The East Texas pipeline expansions include the 36-inch East Texas extension to connect ETP's Reed compressor station in Freestone County to ETP's Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting ETP's Cleburne to Carthage pipeline to the HPL System.

Interstate Transportation and Storage

The following details ETP's pipelines in the interstate transportation and storage operations.

Florida Gas Transmission Pipeline

- Capacity of 3.1 Bcf/d
- Approximately 5,400 miles of interstate natural gas pipeline
- FGT is owned by Citrus, a 50/50 joint venture with Kinder Morgan, Inc. ("KMI")

The Florida Gas Transmission pipeline is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,400 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The Florida Gas Transmission pipeline system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering over 63% of the natural gas consumed in the state. In addition, Florida Gas Transmission's pipeline system operates and maintains over 75 interconnects with major interstate and intrastate natural gas pipelines, which provide FGT's customers access to diverse natural gas producing regions.

FGT's customers include electric utilities, independent power producers, industrials and local distribution companies.

Transwestern Pipeline

- Capacity of 2.1 Bcf/d
- Approximately 2,600 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Transwestern pipeline is an open-access interstate natural gas pipeline extending from the gas producing regions of West Texas, eastern and northwestern New Mexico, and southern Colorado primarily to pipeline interconnects off the east end of its system and to pipeline interconnects at the California border. The Transwestern pipeline has access to three significant gas basins: the Permian Basin in West Texas and eastern New Mexico; the San Juan Basin in northwestern New Mexico and southern Colorado; and the Anadarko Basin in the Texas and Oklahoma panhandle. Natural gas sources from the San Juan Basin and surrounding producing areas can be delivered eastward to Texas intrastate and mid-continent connecting pipelines and natural gas market hubs as well as westward to markets in Arizona, Nevada and California. Transwestern's Phoenix lateral pipeline, with a throughput capacity of 500 MMcf/d, connects the Phoenix area to the Transwestern mainline.

Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users. Transwestern transports natural gas in interstate commerce.

Panhandle Eastern Pipe Line

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

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

Trunkline Gas Pipeline

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

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

ETP is 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 ETP’s dual 42-inch pipeline system near Carthage, Texas, extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana. The pipeline has a capacity of 2.4 Bcf/d, all of which is sold under long-term contracts ranging from 10 to 15 years.

Fayetteville Express Pipeline

- Capacity of 2.0 Bcf/d
- Approximately 185 miles of interstate natural gas pipeline
- 50/50 joint venture through ETC FEP with Kinder Morgan Energy Partners LP

The Fayetteville Express pipeline is an approximately 185-mile interstate natural gas pipeline that originates near Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The pipeline has long-term contracts for 1.85 Bcf/d ranging from 10 to 12 years.

Sea Robin Pipeline

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

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

Midstream

The following details ETP assets in its midstream operations:

Southeast Texas System

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

The Southeast Texas System is an integrated system that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the East Texas pipeline and is connected to the Oasis pipeline, as well as two power plants. This allows ETP to bypass 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 ETP’s system to produce residue gas and NGLs. Residue gas is delivered into ETP’s intrastate pipelines and NGLs are delivered into ETP’s recently acquired or completed pipelines.

ETP’s treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into ETP’s system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications. In addition, ETP’s conditioning facilities remove heavy hydrocarbons from the gas gathered into ETP’s 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 ETP's 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

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

Eagle Ford System

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

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

Other Midstream Assets

The midstream operations also include ETP's 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. ETP also owns approximately 35 miles of gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

NGL Transportation and Services

The following details ETP's assets in the NGL transportation and services operations. Certain assets described below are owned by Lone Star, a joint venture with Regency.

West Texas System

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

The West Texas System, owned by Lone Star, is an intrastate NGL pipeline consisting of 3-inch to 16-inch long-haul, mixed NGLs transportation pipeline that delivers 137,000 Bbls/d of capacity from processing plants in the Permian Basin and Barnett Shale to the Mont Belvieu NGL storage facility.

West Texas Gateway Pipeline

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

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

Other NGL Pipelines

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

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

Mont Belvieu Facilities

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

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

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

Hattiesburg Storage Facility

- Working storage capacity of approximately 4 million Bbls

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

Sea Robin Processing Plant

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

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

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 ETP's assets in its investment in Sunoco Logistics:

Crude Oil Pipelines

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

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

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

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

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

Crude Oil Acquisition and Marketing

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

- purchasing crude oil at the wellhead from producers, and in bulk from aggregators at major pipeline interconnections and trading locations;
- storing inventory during contango market conditions (when the price of crude oil for future delivery is higher than current prices);
- buying and selling crude oil of different grades, at different locations in order to maximize value for producers;
- transporting crude oil on Sunoco Logistics' 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 Sunoco and to third parties, who in turn deliver them to end-users and retail outlets. Terminals are facilities where products are transferred to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. The operation of these facilities is called "terminalling."

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

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

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

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

Hill and West Hackberry Strategic Petroleum Reserve caverns; the Valero pipeline to its Port Arthur, Texas refinery; and the Total pipelines to its Port Arthur, Texas refinery.

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

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

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

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

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

- *Eagle Point Terminal:* The Eagle Point Terminal is located in Westville, New Jersey and consists of docks, truck loading facilities and a tank farm. The docks are located on the Delaware River and can accommodate three ships or barges to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges. The tank farm has a total active storage capacity of approximately 5 million barrels and can receive crude oil and refined products via barge, pipeline and rail. The terminal can deliver via barge, truck, rail or pipeline, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage for clean products and dark oils.

- *Inkster Terminal:* The Inkster Terminal, located near Detroit, Michigan, consists of eight salt caverns with a total storage capacity of approximately 975,000 barrels. The Inkster Terminal's storage is used in connection with the Toledo, Ohio to Sarnia, Canada pipeline system and for the storage of LPGs from Canada and a refinery in Toledo. The terminal can receive and ship LPGs in both directions at the same time and has a propane truck loading rack.

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

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

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

Refined Products Pipelines

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

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

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

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

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

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

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

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

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

Retail Marketing

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

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

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

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

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

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

(1) Gasoline and diesel throughput per company-operated site averaged 200,087 gallons per month during 2013.

(2) Primarily traditional outlets.

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

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

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

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

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

Investment in Regency

The following details the assets in Regency's natural gas operations:

Gathering and Processing Operations

North Louisiana Region

- Approximately 1,201 miles of natural gas pipeline
- Two cryogenic natural gas processing facilities, a refrigeration plant, a conditioning plant and two amine treating plants

Regency's North Louisiana assets gather, compress, treat and dehydrate natural gas in five Parishes (Claiborne, Union, DeSoto, Lincoln and Ouachita) of north Louisiana and Shelby County, Texas. Its assets also include two cryogenic natural gas processing facilities, a refrigeration plant located in Bossier Parish, a conditioning plant located in Webster Parish, an amine treating plant in DeSoto Parish, an amine treating plant in Lincoln Parish, and an interstate NGL pipeline.

In the second quarter of 2013, Regency placed into service an expansion of the Dubach processing facility in North Louisiana that increased the processing capacity of the system to 210 MMcf/d and added high-pressure gathering lines to bring production to the facility.

In mid-2013, Regency began an expansion project to increase the gathering capacity of Regency's Dubberly facility by 400 MMcf/d and a 200 MMcf/d processing upgrade, for $68 million, which is expected to be completed in early 2014.

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.

South Texas Region

- Approximately 1,310 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. Some of the natural gas produced in this region can have significant quantities of hydrogen sulfide and carbon dioxide that require treating to remove these impurities. The pipeline systems that gather this gas are connected to third-party processing plants and Regency's treating facilities that include an acid gas reinjection well 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 and the NGLs-rich and oil-rich Eagle Ford shale formation, which lies directly under Regency's existing South Texas gathering system infrastructure.

Regency owns a 60% interest in Edwards Lime Gathering LLC, Talisman Energy USA Inc. and Statoil Texas Onshore Properties LP owns 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. In October 2013, an expansion of Edwards Lime Gathering LLC was completed to increase the system's capacity to 160 MMcf/d and provide for oil transportation and stabilization capacity of 17,000 Bbls/d.

Permian Region

- Approximately 6,597 miles of natural gas pipeline
- Seven processing and treating plants, a cryogenic natural gas processing plants, and a refrigeration plant

Regency's Permian Basin gathering system assets offer wellhead-to-market services to producers in the Texas counties of Ward, Winkler, Reeves and Pecos counties which surround the Waha Hub, one of Texas' 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 we gather and process, 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. Regency expanded its Permian Basin region through the SUGS acquisition, which increased their presence in the Permian Basin of Texas into Crocket, Upton, Crane, Ector, Culberson, Reagan and Andrews counties, as well as into the Eddy and Lea counties of New Mexico.

Regency offers producers up to four different levels of natural gas compression on the Permian Basin gathering systems, as compared to the two levels typically offered in the industry. By offering multiple levels of compression, Regency's gathering system is often more cost-effective for producers, since the producer is typically not required to pay for a level of compression that is higher than the level they require.

Regency's Permian region assets consist of a network of natural gas and NGL pipelines, seven processing plants and seven natural gas treating plants. These assets offer a broad array of services to producers including field gathering and compression of natural gas; treating, dehydration, sulfur recovery and reinjection and other conditioning; and natural gas processing and marketing of natural gas and NGLs.

In August 2013, Regency placed into service the $330 million expansion of Regency's Red Bluff processing plant, which increased capacity to 940 MMcf/d.

Regency also 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.

Mid-Continent Region

- Approximately 3,493 miles of natural gas pipeline
- One processing plant

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. 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 from 1,500 wells. These systems are geographically concentrated, with each central facility located within 90 miles of the others. 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.

Natural Gas Transportation Operations

RIGS has the capacity to transport up to 2.1 Bcf/d of natural gas. Results of RIGS's operations are determined primarily by the volumes of natural gas transported and subscribed on its intrastate pipeline system and the level of fees charged to customers or the margins received from purchases and sales of natural gas. RIGS generates revenues and margins principally under fee-based transportation contracts. The fixed capacity reservation charges related to RIGS that are not directly dependent on throughput volumes or commodity prices represent 93% of HPC's margin.

MEP pipeline system, operated by Kinder Morgan Energy Partners LP, has the capability to transport up to 1.8 Bcf/d of natural gas, and the pipeline capacity 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.

NGL Services Operations

Regency owns a 30% membership interest in Lone Star, which is a joint venture with ETP owning the remaining 70% membership interest. See "*NGL Transportation and Services"* under ETP's asset overview discussion for additional details.

Contract Services Operations

Regency's contract services operations can be divided into contract compression services and contract treating services. The natural gas contract compression services include designing, sourcing, owning, installing, operating, servicing, repairing and maintaining compressors and related equipment for which Regency guarantees their customers 98% mechanical availability for land installations and 96% mechanical availability for over-water installations. Regency focuses on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering and natural gas processing. Regency believes that it improves the stability of its cash flow by focusing on field-wide compression applications because such applications generally involve long-term installations of multiple large horsepower compression units. Regency's contract compression operations are located in Texas, Oklahoma, Louisiana, Arkansas, Pennsylvania, New Mexico, Colorado and California.

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.

Investment in Trunkline LNG

Trunkline LNG owns a strategically located facility on a 382-acre site in the Lake Charles Harbor and Terminal District, approximately 9 miles southwest of Lake Charles, Louisiana. The facility offers flexibility to worldwide suppliers and buyers with a natural gas peak sendout capacity of up to 2.1 bcf/d and has a firm sustained capacity of 1.8 bcf/d (or 13.7 million metric tons per annum). With the facility's connection to Trunkline's South Louisiana pipeline, the terminal has access to 20 natural gas pipelines and the Henry Hub.

LNG Storage

The facility contains four LNG storage tanks (three of which are 196 feet in diameter and 163 feet tall and one is 232 feet in diameter and 205 feet tall) with combined capacity of approximately 2.7 million barrels of LNG and were specially designed and constructed to store LNG at cryogenic temperatures for sustained periods. The tanks maintain LNG in a liquid state by auto-refrigeration of the boil-off. Boil-off gas can be used for plant fuel, recombined with LNG before it is vaporized or sent directly to sendout. Each tank has three submerged pumps of which two are required to meet maximum LNG sendout capacity.

Sendout System

Prior to vaporization, secondary pumps increase the pressure of the LNG to meet pipeline requirements. Each of the 14 gas-fired, water-bath vaporizers can regasify LNG at a rate of 150 MMcf/d. The facility is connected to the mainline transmission system of Trunkline by dual 23 mile pipelines with a total capacity of 2.1 Bcf/d.

Competition

Natural Gas

The business of providing natural gas gathering, compression, treating, transporting, storing and marketing services is highly competitive. Since pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our transportation and storage operations are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability.

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

In marketing natural gas, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

NGL

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

Crude and Refined Products

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

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

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

Retail Marketing

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

Credit Risk and Customers

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

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

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

During the year ended December 31, 2013, none of our individual customer 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 NGA, the FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, "transportation" includes natural gas pipeline transmission (forwardhauls and backhauls), storage and other services. The Florida Gas Transmission, Transwestern, Panhandle Eastern, Trunkline Gas, Tiger, Fayetteville Express and Sea Robin pipelines transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain storage facilities that are subject to the FERC's regulatory oversight.

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

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

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

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

In 2011, in lieu of filing a new NGA Section 4 general rate case, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. In general, the settlement provides for the continued use of Transwestern's currently effective transportation and fuel tariff rates, with the exception of certain San Juan Lateral fuel rates, which we were required to reduce over a three year period beginning in April 2012. The settlement also resolves certain non-rate matters, and approves Transwestern's use of certain previously approved accounting methodologies. Under the settlement, Transwestern is required to file a new NGA Section 4 rate case on October 1, 2014.

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

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

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

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (1) to defraud using any device, scheme or artifice; (2) to make any untrue statement of material fact or omit a material fact; or (3) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The CFTC also holds authority to monitor certain operations 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 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 operations 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 Refined Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992, and related rules and orders. The ICA requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory and that such rates and terms and conditions of service be filed with the FERC. This statute also permits interested persons to challenge proposed new or changed rates. The FERC is authorized to suspend the effectiveness of such rates for up to seven months, though rates are typically not suspended for the maximum allowable period. If the FERC finds that the new or changed rate is unlawful, it may require the carrier to pay refunds for the period that the rate was in effect. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The FERC generally has not investigated interstate rates on its own initiative when those rates, like those we charge, have not been the subject of a protest or a complaint by a shipper. However, the FERC could investigate our rates at the urging of a third party if the third party is either a current shipper or has a substantial economic interest in the tariff rate level. Although no assurance can be given that the tariffs charged by us ultimately will be upheld if challenged, management believes that the tariffs now in effect for our pipelines are within the maximum rates allowed under current FERC guidelines.

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

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

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the DOT, under the PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (“HLPSA”), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 (“PSI Act”) and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (“PIPES Act”). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas (“HCAs”), which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Failure to comply with the safety laws and regulations may result in the imposition of administrative, civil and criminal remedies. The “rural gathering exemption” under the NGPSA presently exempts substantial portions of our gathering facilities from jurisdiction under the NGPSA, but does not apply to our intrastate natural gas pipelines. The portions of our facilities that are exempt include those portions located outside of cities, towns or any area designated as residential or commercial, such as a subdivision or shopping center. Changes to federal pipeline safety laws and regulations are being considered by Congress or PHMSA including changes to the “rural gathering exemption,” which may be restricted in the future. While we believe our pipeline operations are in substantial compliance with applicable pipeline safety laws, safety laws and regulations may be made more stringent and penalties could be increased. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service.

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

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

Environmental Matters

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

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

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

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

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

As of December 31, 2013 and 2012, accruals of $403 million and $212 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities including certain matters assumed in connection with our acquisition of the HPL System, the Transwestern acquisition, potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors, the predecessor owner's share of certain environmental liabilities of ETC OLP.

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

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

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

Under various environmental laws, including the RCRA (which relates to solid and hazardous waste treatment, storage and disposal), the Partnership has initiated corrective remedial action at its facilities, formerly owned facilities and third-party sites. At the Partnership's major manufacturing facilities, we have consistently assumed continued industrial use and a containment/remediation strategy focused on eliminating unacceptable risks to human health or the environment. The remediation accruals for these sites reflect that strategy. Accruals include amounts to prevent off-site migration and to contain the impact on the facility property, as well as to address known, discrete areas requiring remediation within the plants. Activities include closure of RCRA solid waste management units, recovery of hydrocarbons, handling of impacted soil, mitigation of surface water impacts and prevention of off-site migration. A change in this approach as a result of changing the intended use of a property or a sale to a third party could result in a higher cost remediation strategy in the future.

The Partnership currently owns or operates certain retail gasoline outlets where releases of petroleum products have occurred. Federal and state laws and regulations require that contamination caused by such releases at these sites and at formerly owned sites be assessed and remediated to meet the applicable standards. Our obligation to remediate this type of contamination varies, depending on the extent of the release and the applicable laws and regulations. A portion of the remediation costs may be recoverable from the reimbursement fund of the applicable state, after any deductible has been met.

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

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

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

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by PCBs, and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2025 is $7 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will be required to incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. We believe that our operations are in substantial compliance with the federal Clean Air Act and comparable state laws. The EPA and state agencies are continually considering, proposing or finalizing new rules and regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, EPA has recently finalized new source performance standards (NSPS) for the oil and gas source category. New Subpart OOOO expands the NSPS oil and gas source category to include all operations of the oil and gas industry. It imposes new controls for emissions of volatile organic compounds (VOCs) on well completions, pneumatic devices, compressors, storage vessels and equipment leaks. In addition, EPA has also recently finalized revisions to Subparts HH and HHH that will further reduce emissions of hazardous air pollutants from storage tanks and tri-ethylene glycol dehydrators at major sources. These new regulations will increase our cost of compliance.

On October 19, 2010, the EPA adopted new national emission standards for hazardous air pollutants for existing stationary spark ignition reciprocating internal combustion engines that are either located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions. All engines subject to these "Quad Z" regulations were required to comply by October 19, 2013. Many of our facilities, including our leased compressors have been impacted by these new rules. We have incurred increased costs to bring engines into compliance with the new emission requirements, but such costs were not material.

Clean Water Act. The Federal Water Pollution Control Act of 1972, also known as Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that our continued compliance with such existing permit conditions will not have a material adverse effect on our business, financial condition or results of operations.

Spills. Our operations can result in the discharge of regulated substances, including NGLs, crude oil or refined products. The Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of regulated substances into state waters or waters of the United States. The Clean Water Act and comparable state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges. The Oil Pollution Act subjects owners of covered facilities to strict joint and potentially unlimited liability for removal costs and other consequences of a release of oil, where the release is into navigable waters, along shorelines or in the exclusive economic zone of the United States. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require that containment dikes and similar structures be installed to help prevent the impact on navigable waters in the event of a release. The Office of Pipeline Safety of the DOT, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans, and our management believes we are in substantial compliance with these laws.

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

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitat. Similar protection is 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. On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, would restrict emissions of greenhouse gases from motor vehicles as well as established Prevention of Significant Deterioration ("PSD") and Title V permitting reviews for certain large stationary sources that are potential sources of greenhouse gas emissions. Facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" standards for greenhouse gases, which are developed on a case-by-case basis. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce or sequester emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our services.

In addition, the EPA has published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, including onshore oil and natural gas production, processing, transmission, storage and distribution facilities. We are monitoring greenhouse gas emissions from certain of our operations in accordance with the greenhouse gas emissions reporting rule and believe that our monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

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

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

Employee Health and Safety. We are subject to the requirements of the federal OSHA and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements including general industry standards, recordkeeping requirements, and monitoring of occupational exposure to regulated substances.

Employees

As of January 31, 2014, ETE and its consolidated subsidiaries employed an aggregate of 13,573 employees, 1,466 of which are represented by labor unions. We and our subsidiaries believe that our relations with our employees are satisfactory.

SEC Reporting

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the Securities and Exchange Commission ("SEC"). From time to time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports on our internet website located at http://www.energytransfer.com. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC. Information contained on our website is not part of this report.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

Energy Transfer Equity, L.P. is a Delaware limited partnership whose common units are publicly traded on the NYSE under the ticker symbol "ETE." ETE was formed in September 2002 and completed its initial public offering in February 2006.

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 "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 "Part I—Item 1A. Risk Factors" in the Partnership's Report on Form 10-K for the year ended December 31, 2013 filed with the Securities and Exchange Commission on February 27, 2014.

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ETE" mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, ETP GP, ETP LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Sunoco Logistics and Holdco. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

OVERVIEW

Energy Transfer Equity, L.P. directly and indirectly owns equity interests in ETP and Regency, both publicly traded master limited partnerships engaged in diversified energy-related services.

At December 31, 2013, our interests in ETP and Regency consisted of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49.6	26.3
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency, both of which are publicly traded master limited partnerships engaged in diversified energy-related services. The Parent Company's primary cash requirements are for distributions to its partners, general and administrative expenses, debt service requirements and at ETE's election, capital contributions to ETP and Regency in respect of ETE's general partner interests in ETP and Regency. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of subsidiaries.

In order to fully understand the financial condition and results of operations of the Parent Company on a stand-alone basis, we have included discussions of Parent Company matters apart from those of our consolidated group.

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 subsidiaries' natural gas and NGL businesses through, among other things, pursuing certain construction and expansion opportunities relating to our subsidiaries' existing infrastructure and acquiring certain strategic operations and businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash our subsidiaries generate from their operations.

As a result of the acquisition of Trunkline LNG in February 2014, our reportable segments were re-evaluated and currently reflect the following reportable segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Regency, including the consolidated operations of Regency;
- Investment in Trunkline LNG, including the consolidated operations of Trunkline LNG; and
- Corporate and Other, including the following:
    - activities of the Parent Company; and
    - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

Each of the respective general partners of ETP and Regency have separate operating management and boards of directors. We control ETP and Regency through our ownership of their respective general partners.

Recent Developments

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The 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.

ETP Note Exchange

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

Sale of AmeriGas Common Units

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

Class H Units

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

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

LNG Export Project

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

Sale of Southern Union's Distribution Operations

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, net of 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.

Regency's Pending Acquisition of PVR

In October 2013, Regency entered into a merger agreement with PVR pursuant to which Regency intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The PVR Acquisition is expected to enhance our 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. The PVR Acquisition is expected to close in late March 2014, subject to receipt of the affirmative vote of a majority of the PVR common units outstanding at a meeting scheduled to be held on March 20, 2014 and subject to the satisfaction of other customary closing conditions.

Regency's Pending Acquisition of Eagle Rock's Midstream Business

In December 2013, Regency entered into an agreement to purchase Eagle Rock's midstream business for $1.3 billion. This acquisition is expected to complement Regency's core gathering and processing business and further diversify Regency's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, subject to receipt of the affirmation vote of a majority of the outstanding Eagle Rock common units and subject to the satisfaction of other customary closing conditions, including anti-trust clearance under Hart-Scott Rodino Antitrust Improvements Act.

Regency's Acquisition of Hoover Energy

On February 3, 2014, Regency completed its previously announced acquisition of the midstream assets of Hoover Energy. The consideration paid by Regency in exchange for the acquired Hoover entities was valued at $282 million (subject to customary post-closing adjustments) and consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy and (ii) $184 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. Regency financed the cash portion of the purchase price through borrowings under its revolving credit facility.

ETP's Retail Acquisition

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

Second Fractionator at Lone Star's Mont Belvieu Facility

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

ETE Refinancing Activities

In December 2013, ETE completed a tender offer for a portion of its outstanding 7.50% Senior Notes due 2020. In conjunction with the tender offer, ETE completed a comprehensive refinancing of its existing debt, which included the public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024, a new $1 billion term loan facility, and a new $600 million revolving credit facility. In February 2014, ETE increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the "Panhandle Merger"), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union's obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million Regency Common Units and 6.3 million Regency Class F Units), and ETP (2.2 million ETP Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings' guarantee of $600 million of Regency senior notes.

Trunkline LNG Transaction

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

Results of Operations

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

ETP's contribution of SUGS to Regency on April 30, 2013 was recorded by Regency as a reorganization of entities under common control. Accordingly, Regency retrospectively adjusted its consolidated financial statements to reflect the consolidation of SUGS beginning March 26, 2012 (the date ETE acquired Southern Union, the previous parent of SUGS). Amounts reflected herein for Regency reflect its retrospective consolidation of SUGS.

ETP maintains continuing involvement with SUGS through its affiliation with Regency, including ETP's investment in Regency common and Class F units received as partial consideration for the SUGS contribution. Accordingly, ETP did not record the results of SUGS as discontinued operations; therefore, the results of ETP included herein reflected consolidation of SUGS from March 26, 2012 through April 30, 2013.

As a result, the results of SUGS for March 26, 2012 through April 30, 2013 are included in segment results for both the investment in ETP and the investment in Regency segments in the "Segment Operating Results" section below and in Segment Adjusted EBITDA for both segments in the consolidated results table below. The results of SUGS during that period are separately eliminated in the consolidated results below in order to reconcile to ETE's consolidated net income.

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 includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership and amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations.

ETP's Segment Adjusted EBITDA reflected the results of Trunkline LNG prior to the Trunkline LNG Transaction, which was effective January 1, 2014. The Investment in Trunkline LNG segment reflected the results of operations of Trunkline LNG.

Consequently, the results of operations of Trunkline LNG were reflected in two segments beginning March 26, 2012. Therefore, the results of Trunkline LNG were included in eliminations beginning March 26, 2012.

Consolidated Results

	Years Ended December 31,		
	2013	2012	Change
Segment Adjusted EBITDA:			
Investment in ETP	$ 3,953	$ 2,744	$ 1,209
Investment in Regency	608	517	91
Investment in Trunkline LNG	187	135	52
Corporate and Other	(43)	(52)	9
Adjustments and eliminations	(338)	(239)	(99)
Total	4,367	3,105	1,262
Depreciation and amortization	(1,313)	(871)	(442)
Interest expense, net of interest capitalized	(1,221)	(1,018)	(203)
Bridge loan related fees	—	(62)	62
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	53	(19)	72
Non-cash unit-based compensation expense	(61)	(47)	(14)
Unrealized gains on commodity risk management activities	48	10	38
LIFO valuation adjustments	3	(75)	78
Losses on extinguishments of debt	(162)	(123)	(39)
Adjusted EBITDA related to discontinued operations	(76)	(99)	23
Adjusted EBITDA related to unconsolidated affiliates	(727)	(647)	(80)
Equity in earnings of unconsolidated affiliates	236	212	24
Non-operating environmental remediation	(168)	—	(168)
Other, net	(2)	14	(16)
Income from continuing operations before income tax expense	375	1,437	(1,062)
Income tax expense	93	54	39
Income from continuing operations	282	1,383	(1,101)
Income (loss) from discontinued operations	33	(109)	142
Net income	$ 315	$ 1,274	$ (959)

See the detailed discussion of Segment Adjusted EBITDA in the Segment Operating Results section 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 Sunoco Logistics of $265 million in 2013 compared to $63 million from October 5, 2012 through December 31, 2012;
- depreciation and amortization related to Sunoco of $113 million in 2013 compared to $32 million from October 5, 2012 through December 31, 2012;

- depreciation and amortization related to Southern Union of $189 million in 2013 compared to $179 million from March 26, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2013 and 2012.

Interest Expense, Net of Interest Capitalized. Interest expense increased primarily due to the following:

- interest expense related to Sunoco Logistics of $76 million in 2013 compared to $14 million from October 5, 2012 through December 31, 2012;
- interest expense related to Sunoco of $33 million in 2013 compared to $9 million from October 5, 2012 through December 31, 2012;
- incremental interest expense due to ETP’s issuance of $1.25 billion of senior notes in January 2013 and $1.5 billion of senior notes in September 2013; and
- an increase of $42 million related to Regency primarily due to its issuance of $700 million of senior notes in October 2012, $600 million of senior notes in April 2013 and $400 million of senior notes in September 2013; partially offset by
- a reduction of $25 million for the Parent Company primarily related to a $1.1 billion principal paydown of the Parent Company’s $2 billion term loan in April 2013.

Bridge Loan Related Fees. The bridge loan commitment fee recognized during the year ended December 31, 2012 was incurred in connection with the Southern Union Merger. The Parent Company obtained permanent financing for the transaction through a $2 billion senior secured term loan which was funded upon closing of the Southern Union Merger on March 26, 2012.

Gain on Deconsolidation of Propane Business. ETP recognized a gain on deconsolidation related to the contribution of its Propane Business to AmeriGas in January 2012.

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

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

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

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

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

Losses on Extinguishments of Debt. For the year ended December 31, 2013, the loss on extinguishment of debt was primarily related to ETE’s refinancing transactions completed in December 2013. For the year ended December 31, 2012, ETP recognized a loss on extinguishment of debt in connection with its repurchase of approximately $750 million in aggregate principal amount of senior notes in January 2012. In addition, Regency recognized a $7 million loss on extinguishment of debt in connection with its repurchase of senior notes in June 2013 and an $8 million loss in connection with its repurchases of senior notes in May 2012.

Adjusted EBITDA Related to Discontinued Operations. For the year ended December 31, 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. For the year ended December 31, 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. See additional discussion of results in “Segment Operating Results” below.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected primarily include our proportionate share of such amounts related to AmeriGas, FEP, HPC and MEP, as well as Citrus beginning March 26, 2012. See additional discussion of results in “Segment Operating Results” below.

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

Other, net. Includes amortization of regulatory assets and other income and expense amounts.

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

Supplemental Pro Forma Financial Information

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

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

	ETE Historical	Propane Transaction[(a)]	Sunoco Historical[(b)]	Southern Union Historical[(c)]	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	14,204	(80)	33,142	302	(11,193)	36,375
Depreciation and amortization	871	(4)	168	49	76	1,160
Selling, general and administrative	529	(1)	459	11	(119)	879
Impairment charges	—		124		(22)	102
Total costs and expenses	15,604	(85)	33,893	362	(11,258)	38,516
OPERATING INCOME	1,360	(8)	1,365	81	(916)	1,882
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(1,080)	(24)	(123)	(50)	2	(1,275)
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	(123)	115	—	—	—	(8)
Losses on interest rate derivatives	(19)	—	—	—	—	(19)
Other, net	30	2	118	(2)	(2)	146
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	1,437	(953)	2,545	45	(2,055)	1,019
Income tax expense (benefit)	54	—	956	12	(871)	151
INCOME FROM CONTINUING OPERATIONS	$ 1,383	$ (953)	$ 1,589	$ 33	$ (1,184)	$ 868

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

	ETE Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$ 8,190	$ (1,427)	$ 45,328	$ 1,997	$ (16,528)	$ 37,560
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	6,114	(1,174)	44,119	1,338	(16,677)	33,720
Depreciation and amortization	586	(78)	335	204	(2)	1,045
Selling, general and administrative	253	(47)	598	42	(56)	790
Impairment charges	—	—	2,629	—	(2,569)	60
Total costs and expenses	6,953	(1,299)	47,681	1,584	(19,304)	35,615
OPERATING INCOME	1,237	(128)	(2,353)	413	2,776	1,945
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(740)	(40)	(172)	(218)	29	(1,141)
Equity in earnings of affiliates	117	148	15	99	(158)	221
Gains (losses) on non-hedged interest rate derivatives	(78)	—	—	—	—	(78)
Impairment charges	(5)	—	—	—	—	(5)
Other, net	17	2	44	—	(2)	61
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	548	(18)	(2,466)	294	2,645	1,003
Income tax expense (benefit)	17	(4)	(1,063)	80	1,070	100
INCOME FROM CONTINUING OPERATIONS	$ 531	$ (14)	$ (1,403)	$ 214	$ 1,575	$ 903

(a) Propane Transaction adjustments reflect the following:

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

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

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

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

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

- 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.

Segment Operating Results

Investment in ETP

	Years Ended December 31,		
	2013	2012	Change
Revenues	$ 46,339	$ 15,702	$ 30,637
Cost of products sold	41,204	12,266	28,938
Gross margin	5,135	3,436	1,699
Unrealized (gains) losses on commodity risk management activities	(51)	9	(60)
Operating expenses, excluding non-cash compensation expense	(1,376)	(949)	(427)
Selling, general and administrative, excluding non-cash compensation expense	(448)	(406)	(42)
Adjusted EBITDA related to discontinued operations	76	99	(23)
Adjusted EBITDA related to unconsolidated affiliates	629	480	149
Other, net	(12)	75	(87)
Segment Adjusted EBITDA	$ 3,953	$ 2,744	$ 1,209

Gross Margin. For the year ended December 31, 2013 compared to the prior year, ETP's gross margin increased primarily as a result of the net impact of the following:

- The year ended December 31, 2013 reflected a full year of operations of Sunoco Logistics and ETP's retail marketing operations which were acquired October 5, 2012. Gross margin included in our consolidated results related to Sunoco Logistics and ETP's retail marketing operations increased $761 million and $693 million, respectively, between periods.

- Revenues from ETP's interstate transportation and storage operations increased $200 million primarily as a result of ETP's consolidation of Southern Union's transportation and storage operations beginning March 26, 2012.

- Gross margin related to ETP's NGL transportation and services operations increased $183 million as a result of (i) increases in transportation margin as a result of higher volumes transported out of West Texas due to the completion expansion projects and (ii) higher processing and fractionation margin due to the completion of Lone Star's fractionators in December 2012 and December 2013.

- These increases were partially offset by a decrease of $82 million in gross margin related to ETP's intrastate transportation and storage operations primarily due to the cessation of long-term transportation contracts.

- These increases were further offset by a decrease of $10 million in gross margin related to ETP's midstream operations primarily related to the deconsolidation of SUGS.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized (gains) losses on commodity risk management activities primarily reflected the net impact from unrealized gains and losses on natural gas storage and non-storage derivatives, as well as fair value adjustments to inventory. The increase in unrealized gains on commodity risk management activities for 2013 compared to 2012 was primarily attributable to natural gas storage inventory and related derivatives.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2013 compared to the prior year, ETP's operating expense increased primarily as a result of a full year of operations related to Sunoco Logistics and ETP's retail marketing operations which were acquired on October 5, 2012. Operating expenses included in our consolidated results related to Sunoco Logistics and ETP's retail marketing operations increased $69 million and $316 million, respectively, between periods. In addition, ETP's interstate transportation and storage's operating expenses increased $77 million primarily as a result of ETP's consolidation of Southern Union. Operating expenses for ETP's NGL transportation and services operations increased approximately $49 million primarily due to additional expenses from assets being placed in service. These increases were partially offset by decreases in ETP's operating expenses due to its deconsolidation of certain operations during the periods, including ETP's retail propane operations in January 2012 and SUGS in April 2013.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2013 compared to the prior year, ETP's selling, general and administrative expenses increased primarily as a result of a full year of operations related to Sunoco Logistics and ETP's retail marketing operations which were acquired on October 5, 2012. Selling, general and administrative expenses included in our consolidated results related to Sunoco Logistics and ETP's retail marketing operations increased $78 million and $84 million, respectively, between periods. These increases were partially offset by decreases in ETP's interstate transportation and storage operations and midstream operations of $65 million and $36 million, respectively, primarily as a result of merger-related expenses recorded in 2012 and cost reduction initiatives in 2013.

Adjusted EBITDA Related to Discontinued Operations. In 2013, amounts reflect 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 reflect the operations of Canyon, which was sold in October 2012, and, for the period from March 26, 2012 to December 31, 2012, Southern Union's distribution operations.

Adjusted EBITDA Related to Unconsolidated Affiliates. ETP's Adjusted EBITDA related to unconsolidated affiliates for the years ended December 31, 2013 and 2012 consisted of the following:

	Years Ended December 31,		
	2013	2012	Change
AmeriGas	$ 175	$ 139	$ 36
Citrus	296	228	68
FEP	75	77	(2)
Regency	66	—	66
Other	17	36	(19)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 629	$ 480	$ 149

Amounts reflected above include a partial period for Citrus and AmeriGas in 2012 and a partial period for Regency in 2013.

Other. Other amounts in 2013 were primarily related to Sunoco's recognition of environmental obligations related to closed sites. Other amounts in 2012 were primarily related to Sunoco's LIFO valuation adjustments.

Investment in Regency

	Years Ended December 31,		
	2013	2012	Change
Revenues	$ 2,521	$ 2,000	$ 521
Cost of products sold	1,793	1,387	406
Gross margin	728	613	115
Unrealized (gains) losses on commodity risk management activities	9	(5)	14
Operating expenses, excluding non-cash compensation expense	(289)	(228)	(61)
Selling, general and administrative, excluding non-cash compensation expense	(81)	(95)	14
Adjusted EBITDA related to unconsolidated affiliates	250	222	28
Other, net	(9)	10	(19)
Segment Adjusted EBITDA	$ 608	$ 517	$ 91

Gross Margin. Regency's gross margin increased for the year ended December 31, 2013 compared to the prior year primarily due to increased volumes in Regency's South and West Texas gathering and processing operations.

Operating Expenses, Excluding Non-Cash Compensation Expense. Regency's operating expenses increased primarily due to the consolidation of SUGS beginning March 26, 2012 and increased pipeline and plant operating activity from organic growth.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Regency's selling, general and administrative expenses decreased due to the elimination of the amount allocated to SUGS assets by the previous parent and the decrease in management fees paid to ETE, partially offset by an increase in legal and consulting fees.

Adjusted EBITDA Related to Unconsolidated Affiliates. Regency's adjusted EBITDA related to unconsolidated affiliates increased $30 million primarily due to the impact from Lone Star.

Other. Regency's other decreased primarily as the result of recognition of a one-time producer payment received in March 2012 related to an assignment of certain contracts.

Investment in Trunkline LNG

	Years Ended December 31,		
	2013	2012	Change
Revenues	$ 216	$ 166	$ 50
Operating expenses, excluding non-cash compensation expense	(20)	(12)	(8)
Selling, general and administrative, excluding non-cash compensation expense	(9)	(19)	10
Segment Adjusted EBITDA	$ 187	$ 135	$ 52

Amounts reflected above include the results of Trunkline LNG beginning March 26, 2012, the date which ETE obtained control of Trunkline LNG through the acquisition of Southern Union.

Trunkline LNG derives all of its revenue from a contract with a non-affiliated gas marketer.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2013 compared to the prior year, Trunkline LNG's operating expense increased primarily as a result of a full year of operations which were consolidated beginning on March 26, 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. The decrease in expense compared to the prior year was primarily a result of $9 million of merger-related expenses recorded in 2012.

Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011 (tabular dollar amounts are expressed in millions)

Consolidated Results

	Years Ended December 31,		
	2012	2011	Change
Segment Adjusted EBITDA:			
Investment in ETP	$ 2,744	$ 1,781	$ 963
Investment in Regency	517	420	97
Investment in Trunkline LNG	135	—	135
Corporate and Other	(52)	(29)	(23)
Adjustments and Eliminations	(239)	(41)	(198)
Total	3,105	2,131	974
Depreciation and amortization	(871)	(586)	(285)
Interest expense, net of interest capitalized	(1,018)	(740)	(278)
Bridge loan related fees	(62)	—	(62)
Gain on deconsolidation of Propane Business	1,057	—	1,057
Losses on non-hedged interest rate derivatives	(19)	(78)	59
Non-cash unit-based compensation expense	(47)	(42)	(5)
Unrealized gains on commodity risk management activities	10	7	3
LIFO valuation adjustments	(75)	—	(75)
Losses on extinguishments of debt	(123)	—	(123)
Adjusted EBITDA related to discontinued operations	(99)	(23)	(76)
Adjusted EBITDA related to unconsolidated affiliates	(647)	(231)	(416)
Equity in earnings of unconsolidated affiliates	212	117	95
Other, net	14	(7)	21
Income from continuing operations before income tax expense	1,437	548	889
Income tax expense	54	17	37
Income from continuing operations	1,383	531	852
Loss from discontinued operations	(109)	(3)	(106)
Net income	$ 1,274	$ 528	$ 746

See the detailed discussion of Segment Adjusted EBITDA in the Segment Operating Results section below.

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

- depreciation and amortization related to Southern Union of $179 million from March 26, 2012 to December 31, 2012;
- depreciation and amortization related to Sunoco Logistics and Sunoco of $63 million and $32 million, respectively, from October 5, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2012 and 2011; partially offset by
- the deconsolidation of ETP’s Propane Business in January 2012, which had recognized depreciation of $4 million and $82 million for years ended December 31, 2012 and 2011, respectively.

Interest Expense, Net of Interest Capitalized. Interest expense increased primarily due to:

- interest expense of $130 million recorded by Southern Union from March 26, 2012 through December 31, 2012;

- interest expense related to Sunoco Logistics and Sunoco of $14 million and $9 million, respectively, from October 5, 2012 to December 31, 2012;
- incremental interest expense recorded by ETP primarily due to the issuance of $1.5 billion of senior notes in May 2011 and $2.0 billion of notes in January 2012 to fund acquisitions; and
- an increase of $71 million for the Parent Company primarily related to the Parent Company's $2.0 billion Senior Secured Term Loan which was used to fund a portion of the cash consideration for the Southern Union Merger; partially offset by
- a reduction of interest due to ETP's repurchase of $750 million of its senior notes in January 2012.

Gain on Deconsolidation of Propane Business. ETP recognized a gain on deconsolidation related to the contribution of its Propane Business to AmeriGas in January 2012.

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

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

Unrealized Gains (Losses) on Commodity Risk Management Activities. See additional discussion of the unrealized gains (losses) on commodity risk management activities included in the discussion of segment results below.

Losses on Extinguishments of Debt. ETP recognized a loss on extinguishment of debt for the year ended December 31, 2012 in connection with its repurchase of approximately $750 million in aggregate principal amount of senior notes in January 2012.

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

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected for 2012 primarily include our proportionate share of such amounts related to AmeriGas, Citrus, FEP, HPC and MEP. The 2011 amounts primarily represented our proportionate share of such amounts and do not include AmeriGas and Citrus.

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

Income Tax Expense. The increase in income tax expense for the year ended December 31, 2012 compared to the same periods last year were primarily due to our acquisition of Southern Union in March 2012 which has a higher overall effective rate as Southern Union is subject to federal and state income taxes.

Segment Operating Results

Investment in ETP

	Years Ended December 31,		
	2012	2011	Change
Revenues	$ 15,702	$ 6,799	$ 8,903
Cost of products sold	12,266	4,175	8,091
Gross margin	3,436	2,624	812
Unrealized losses on commodity risk management activities	9	11	(2)
Operating expenses, excluding non-cash compensation expense	(949)	(798)	(151)
Selling, general and administrative, excluding non-cash compensation expense	(406)	(135)	(271)
Adjusted EBITDA related to discontinued operations	99	23	76
Adjusted EBITDA related to unconsolidated affiliates	480	56	424
Other, net	75	—	75
Segment Adjusted EBITDA	$ 2,744	$ 1,781	$ 963

Gross Margin. For the year ended December 31, 2012 compared to the year ended December 31, 2011, gross margin increased $812 million, primarily as a result of ETP's acquisition of Sunoco, including Sunoco Logistics and retail marketing operations, in conjunction with the Holdco Transaction in October 2012. Sunoco Logistics' gross margin was $304 million for October 5, 2012 to December 31, 2012, and retail marketing gross margin was $169 million for October 5, 2012 to December 31, 2012. In addition, NGL transportation and services gross margin increased $110 million, as the NGL transportation and services operations gross margin reflected twelve months of activity compared to only eight months of activity in 2011. Midstream gross margin increased $185 million primarily due to increased volumes and the consolidation of Southern Union's gathering and process business from March 26, 2012 to December 31, 2012. These increases were partially offset by decreases in ETP's intrastate transportation and storage gross margin of $103 million over the period, primarily due to the cessation of certain long-term transportation contracts and a continued unfavorable natural gas price environment.

Unrealized Losses on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities primarily reflected the net impact from unrealized gains and losses on natural gas storage and non-storage derivatives, as well as fair value adjustments to inventory. The decrease in unrealized losses on commodity risk management activities for 2012 compared to 2011 was primarily attributable to natural gas storage inventory and related derivatives.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2012 compared to the year ended December 31, 2011, ETP's operating expense increases of $48 million were attributable to Sunoco Logistics and $119 million were attributable to ETP's retail marketing operations. As discussed above, Sunoco Logistics and the retail marketing operations were acquired in October of 2012. For the year ended December 31, 2012, the increase in operating expenses also reflects a $154 million increase in ETP's interstate transportation and storage operations primarily due to the consolidation of Southern Union beginning March 26, 2012. In addition, midstream operation expenses increased $78 million primarily due to the consolidation of Southern Union. These amounts were partially offset by a $298 million decrease in operating expense attributable to ETP's all other operations, primarily due to the contribution of ETP's propane business to AmeriGas in January 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2012 compared to the year ended December 31, 2011, ETP's selling, general and administrative increased $119 million due to the consolidation of Southern Union's transportation and storage operations in ETP's interstate transportation and storage operations and $46 million due to the consolidation of Southern Union's gathering and processing operations in ETP's midstream operations beginning March 26, 2012, $32 million due to the consolidation of Sunoco Logistics, and $17 million due to the consolidation of ETP's retail marketing operations. As discussed above, Sunoco Logistics and the retail marketing operations were acquired in October of 2012.

Adjusted EBITDA Related to Discontinued Operations. Amounts reflected the operations of Canyon, which was sold in October 2012, and Southern Union's distribution operations beginning March 26, 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates. ETP's Adjusted EBITDA related to unconsolidated affiliates for the years ended December 31, 2012 and 2011 consisted of the following:

	Years Ended December 31,		
	2012	2011	Change
AmeriGas	$ 139	$ —	$ 139
Citrus	228	—	228
FEP	77	53	24
Other	36	3	33
Total Adjusted EBITDA related to unconsolidated affiliates	$ 480	$ 56	$ 424

Amounts reflected above include a partial period for Citrus and AmeriGas in 2012.

Other. Amounts reflected $75 million in LIFO valuation adjustments in ETP's retail marketing operations for the year ended December 31, 2012.

Investment in Regency

	Years Ended December 31,		
	2012	2011	Change
Revenues	$ 2,000	$ 1,434	$ 566
Cost of products sold	1,387	1,013	374
Gross margin	613	421	192
Unrealized gains on commodity risk management activities	(5)	—	(5)
Operating expenses, excluding non-cash compensation expense	(228)	(147)	(81)
Selling, general and administrative, excluding non-cash compensation expense	(95)	(64)	(31)
Adjusted EBITDA related to unconsolidated affiliates	222	213	9
Other, net	10	(3)	13
Segment Adjusted EBITDA	$ 517	$ 420	$ 97

Gross Margin. Regency's gross margin increased approximately $145 million for the year ended December 31, 2012 compared to the prior year due to the consolidation of SUGS beginning March 26, 2012, with the remaining of the change being attributable to increased volumes in Regency's South and West Texas and North Louisiana gathering and processing operations.

Unrealized Gains on Commodity Risk Management Activities. Regency's gains on commodity risk management activities increased primarily due to mark-to-market adjustments on its non-hedged commodity derivatives during the year ended December 31, 2012.

Operating Expenses, Excluding Non-Cash Compensation Expense. Regency's operating expenses, excluding non-cash compensation expenses, increased approximately $62 million due to the consolidation of SUGS beginning March 26, 2012, with the remaining change attributable to increased pipeline and plant operating activity in South and West Texas, increased compressor maintenance expense primarily due to increases in maintenance and materials costs, and increases in ad valorem taxes related to organic growth projects.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Regency's selling, general and administrative expenses, excluding non-cash compensation expense, increased for the year ended December 31, 2012 compared to the prior year primarily due to the consolidation of SUGS beginning March 26, 2012, which was partially offset by a decrease of approximately $4 million as a result of lower professional fees and lower rent expense.

Adjusted EBITDA Related to Unconsolidated Affiliates. Regency's adjusted EBITDA related to unconsolidated affiliates increased for the year ended December 31, 2012 compared to the prior year primarily due to the impact from Lone Star, which was formed in May 2011.

Other. Regency's other increased primarily as the result of recognition of a one-time producer payment received in March 2012 related to an assignment of certain contracts.

Investment in Trunkline LNG

	Years Ended December 31,		
	2012	2011	Change
Revenues	$ 166	$ —	$ 166
Operating expenses, excluding non-cash compensation expense	(12)	—	(12)
Selling, general and administrative, excluding non-cash compensation expense	(19)	—	(19)
Segment Adjusted EBITDA	$ 135	$ —	$ 135

Amounts reflected above include the results of Trunkline LNG beginning March 26, 2012, the date which ETE obtained control of Trunkline LNG through the acquisition of Southern Union.

Trunkline LNG derives all of its revenue from a contract with a non-affiliated gas marketer.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Parent Company Only

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency. Effective with the Parent Company's acquisition of 100% of Trunkline LNG on February 19, 2014, the Parent Company will also generate cash flows through Trunkline LNG's wholly-owned subsidiaries. The amount of cash that ETP and Regency distribute to their respective partners, including the Parent Company, each quarter is based on earnings from their respective business activities and the amount of available cash, as discussed below. In connection with certain transactions we have relinquished a portion of our incentive distributions to be received from ETP and Regency in future quarters, see additional discussion under "Cash Distributions."

The Parent Company's primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners and holders of the Preferred Units. The Parent Company currently expects to fund its short-term needs for such items with cash flows from its direct and indirect investments in ETP, Regency and Holdco. The Parent Company distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its Unitholders on a quarterly basis.

We expect ETP, Regency and Trunkline LNG and their respective subsidiaries to utilize their resources, along with cash from their operations, to fund their announced growth capital expenditures and working capital needs; however, the Parent Company may issue debt or equity securities from time to time, as we deem prudent to provide liquidity for new capital projects of our subsidiaries or for other partnership purposes.

ETP

ETP's ability to satisfy its obligations and pay distributions to its Unitholders will depend on its future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond the control of ETP's management.

ETP currently expects capital expenditures in 2014 to be within the following ranges:

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

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

The assets used in ETP's natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, ETP does not have any significant financial commitments for maintenance capital expenditures in its businesses. From time to time it experiences 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 in a timely manner, higher steel prices and other factors beyond ETP's control. However, ETP includes these factors in its anticipated growth capital expenditures for each year.

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

As of December 31, 2013, in addition to $549 million of cash on hand, ETP had available capacity under its revolving credit facilities of $2.34 billion. Based on ETP's current estimates, it expects to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund its announced growth capital expenditures and working capital needs for the next 12 months; however, ETP may issue debt or equity securities prior to that time as it deems prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

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

Regency

Regency expects its sources of liquidity to include: cash generated from operations and occasional asset sales; borrowings under the Regency Credit Facility; distributions received from unconsolidated affiliates; debt offerings; and issuance of additional partnership units.

In 2014, Regency expects to invest $540 million in growth capital expenditures, of which $230 million is expected to be invested in organic growth projects in the gathering and processing operations; $110 million is expected to be invested in Regency's portion of growth capital expenditures in its NGL services operations; and $200 million is expected to be invested in growth capital expenditures in its contract services operations. In addition, Regency expects to invest $60 million in maintenance capital expenditures in 2014, including its proportionate share related to joint ventures.

Regency may revise the timing of these expenditures as necessary to adapt to economic conditions. Regency expects to fund its growth capital expenditures with borrowings under its revolving credit facility and a combination of debt and equity issuances.

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisition 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 ETP has 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 purchases and sales of inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period:

Year Ended December 31, 2013

Cash provided by operating activities in 2013 was $2.42 billion and net income was $315 million. The difference between net income and cash provided by operating activities in 2013 consisted of net non-cash items totaling $1.94 billion and changes in operating assets and liabilities of $149 million. The non-cash activity consisted primarily of depreciation and amortization of $1.31 billion, goodwill impairment of $689 million, deferred income taxes of $43 million, losses on extinguishments of debt of $162 million and non-cash compensation expense of $61 million.

Year Ended December 31, 2012

Cash provided by operating activities in 2012 was $1.08 billion and net income was $1.27 billion. The difference between net income and cash provided by operating activities in 2012 consisted of net non-cash items totaling $85 million and changes in operating assets and liabilities of $551 million. The non-cash activity consisted primarily of a gain on the deconsolidation of ETP's propane business of $1.06 billion, which was offset by depreciation and amortization of $871 million, losses on extinguishments of debt of $123 million and non-cash compensation expense of $47 million.

Year Ended December 31, 2011

Cash provided by operating activities in 2011 was $1.38 billion and net income was $528 million. The difference between net income and cash provided by operating activities in 2011 consisted of non-cash items totaling $566 million and changes in operating assets and liabilities of $158 million. The non-cash activity consisted primarily of depreciation and amortization of $586 million and non-cash compensation expense of $42 million.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2013

Cash used in investing activities in 2013 of $2.35 billion was comprised primarily of capital expenditures of $3.51 billion (excluding the allowance for equity funds used during construction). ETP invested $2.11 billion for growth capital expenditures and $343 million for maintenance capital expenditures during 2013. Regency invested $948 million for growth capital expenditures and $48 million for maintenance capital expenditures during 2013. These expenditures were partially offset by $1.01 billion and $346 million of cash received from the sale of the MGE and NEG assets and the sale of AmeriGas common units, respectively. In addition, ETP paid net cash of $405 million for acquisitions.

Year Ended December 31, 2012

Cash used in investing activities in 2012 of $4.20 billion was comprised primarily of capital expenditures of $3.27 billion (excluding the allowance for equity funds used during construction). ETP invested $2.74 billion for growth capital expenditures and $313 million for maintenance capital expenditures during 2012. Regency invested $945 million for growth capital expenditures and $58 million for maintenance capital during 2012 (including amounts related to SUGS). Cash paid for the acquisition of Southern Union was $2.97 billion and ETP received $1.44 billion in proceeds from the contribution of propane.

Year Ended December 31, 2011

Cash used in investing activities in 2011 of $3.87 billion was comprised primarily of capital expenditures of $1.81 billion (excluding the allowance for equity funds used during construction). ETP invested $1.35 billion for growth capital expenditures and $134 million for maintenance capital expenditures during 2011. Regency invested $354 million for growth capital expenditures and $22 million for maintenance capital during 2011. In addition, our subsidiaries paid cash for acquisitions of $1.97 billion, which primarily consisted of the acquisition of Lone Star and made net advances to joint ventures of $150 million.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund ETP's and Regency's acquisitions and growth capital expenditures. Distributions increase between the periods based on increases in the number of common units outstanding or increases in the distribution rate.

Following is a summary of financing activities by period:

Year Ended December 31, 2013

Cash provided by financing activities was $146 million in 2013. We had a consolidated increase in our debt level of $983 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). Our subsidiaries also received $1.76 billion in proceeds from common unit offerings, which consisted of $1.61 billion from the issuance of ETP Common Units and $149 million from the issuance of Regency Common Units. We paid distributions to partners of $733 million, and our subsidiaries paid $1.43 billion on limited partner interests other than those held by the Parent Company. We also paid $340 million to redeem our Preferred Units.

Year Ended December 31, 2012

Cash provided by financing activities was $3.36 billion in 2012. We had a consolidated increase in our debt level of $4.02 billion, which primarily consisted of borrowings to fund our acquisitions of Southern Union and Sunoco. Our subsidiaries also received $1.10 billion in proceeds from common unit offerings, which consisted of $791 million from the issuance of ETP Common Units and $312 million from the issuance of Regency Common Units. We paid distributions to partners of $666 million and $24 million to the holders of our Preferred Units. In addition, our subsidiaries paid $1.02 billion on limited partner interests other than those held by the Parent Company.

Year Ended December 31, 2011

Cash provided by financing activities was $2.54 billion in 2011. ETP received $1.47 billion in net proceeds from offerings of ETP Common Units, including $96 million under its equity distribution program (see Note 8 to our consolidated financial statements). In addition, Regency received $436 million in net proceeds from offerings of Regency Common Units. We had a consolidated net increase in our debt level of $2.00 billion and paid distributions of $526 million to our common unitholders and $24 million to the holders of our Preferred Units. In addition, ETP paid distributions of $562 million on limited partner interests other than those held by the Parent Company and Regency paid $217 million on limited partner interests other than those held by the Parent Company. These distributions are reflected as distributions to noncontrolling interests on our consolidated statements of cash flows.

Description of Indebtedness

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

	December 31,	
	2013	2012
Parent Company Indebtedness:		
ETE Senior Notes	$ 1,637	$ 1,800
ETE Senior Secured Term Loan	—	2,000
ETE Senior Secured Revolving Credit Facility	1,171	60
Subsidiary Indebtedness:		
ETP Senior Notes	11,182	7,692
Regency Senior Notes	2,800	1,962
Transwestern Senior Unsecured Notes	870	870
Southern Union Senior Notes	169	1,260
Panhandle Senior Notes	916	1,621
Sunoco Senior Notes	965	965
Sunoco Logistics Senior Notes	2,150	1,450
Revolving Credit Facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2016	65	1,395
Regency $1.2 billion Revolving Credit Facility due May 21, 2018	510	192
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Other long-term debt	228	51
Unamortized premiums and fair value adjustments, net	301	386
Total debt	23,199	22,053
Less: current maturities	637	613
Long-term debt, less current maturities	$ 22,562	$ 21,440

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

Parent Company Indebtedness

On December 2, 2013, the Parent Company completed a public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024. The Parent Company used net proceeds from this offering, together with a portion of the net proceeds from the Revolver Credit Agreement and the ETE Term Loan Facility, discussed below, to fund the Parent Company's tender offer for a portion of its 7.500% Senior Notes due 2020 (together with the 5.875% Senior Notes due 2024, the "ETE Senior Notes").

The ETE Senior Notes are the Parent Company's senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of its future subordinated debt. The Parent Company's obligations under the ETE Senior Notes are secured on a first-priority basis with its obligations under the Revolver Credit Agreement and the ETE Term Loan Facility, by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Senior Notes are not guaranteed by any of the Parent Company's subsidiaries.

The covenants related to the ETE Senior Notes include a limitation on liens, a limitation on transactions with affiliates, a restriction on sale-leaseback transactions and limitations on mergers and sales of all or substantially all of the Parent Company's assets.

ETE Term Loan Facility

On December 2, 2013, the Parent Company entered into a Senior Secured Term Loan Agreement (the "ETE Term Credit Agreement"), which has a scheduled maturity date of December 2, 2019, with an option to extend the term subject to the terms and conditions set forth therein. Pursuant to the ETE Term Credit Agreement, the lenders have provided senior secured financing in an aggregate principal amount of $1.0 billion (the "ETE Term Loan Facility"). The Parent Company shall not be required to make any amortization payments with respect to the term loans under the Term Credit Agreement. Under certain circumstances, the Partnership is required to repay the term loan in connection with dispositions of (a) incentive distribution rights in ETP or Regency, (b) general partnership interests in Regency or (c) equity interests of any Person which owns, directly or indirectly, incentive distribution rights in ETP or Regency or general partnership interests in Regency, in each case, yielding net proceeds in excess of $50 million.

Under the Term Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Term Loan Facility initially is not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The applicable margin for LIBOR rate loans is 2.50% and the applicable margin for base rate loans is 1.50%. Proceeds of the borrowings under the Term Credit Agreement were used to partially fund a tender offer for ETE Senior Notes completed in December 2013, to repay amounts outstanding under the Parent Company's existing term loan credit facility, and to pay transaction fees and expenses related to the tender offer, the ETE Term Loan Facility and other transactions incidental thereto.

ETE Revolving Credit Facility

On December 2, 2013, the Parent Company entered into a credit agreement (the "Revolving Credit Agreement"), which has a scheduled maturity date of December 2, 2018, with an option for the Partnership to extend the term subject to the terms and conditions set forth therein.

Pursuant to the Revolver Credit Agreement, the lenders have committed to provide advances up to an aggregate principal amount of $600 million at any one time outstanding (the "ETE Revolving Credit Facility"), and the Parent Company has the option to request increases in the aggregate commitments provided that the aggregate commitments never exceed $1.0 billion. In February 2014, the Partnership increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

As part of the aggregate commitments under the facility, the Revolver Credit Agreement provides for letters of credit to be issued at the request of the Parent Company in an aggregate amount not to exceed a $150 million sublimit.

Under the Revolver Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets. Borrowings under the Revolver Credit Agreement are not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The issuing fees for all letters of credit are also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the then applicable leverage ratio of the Parent Company. The applicable margin for LIBOR rate loans and letter of credit fees ranges from 1.75% to 2.50% and the applicable margin for base rate loans ranges from 0.75% to 1.50%. The Parent Company will also pay a fee based on its leverage ratio on the actual daily unused amount of the aggregate commitments.

Subsidiary Indebtedness

ETP January 2013 Senior Notes Offering

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

Sunoco Logistics 2013 Senior Notes Offering

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

ETP September 2013 Senior Notes Offering

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

Note Exchange

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

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of ETP's subsidiaries and has equal rights to holders of ETP's 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.

ETP uses the ETP Credit Facility to provide temporary financing for its growth projects, as well as for general partnership purposes. ETP typically repays amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term notes offerings. The timing of borrowings depends on ETP'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. ETP does not believe that such fluctuations indicate a significant change in its liquidity position, because it expects to continue to be able to repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term note offerings.

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

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

Regency Revolving Credit Facility

The Regency Credit Facility has aggregate revolving commitments of $1.20 billion, with a $300 million incremental facility. The maturity date of the Regency Credit Facility is May 21, 2018.

The outstanding balance of revolving loans under the Regency Credit Facility bears interest at LIBOR plus a margin or an alternate base rate. The alternate base rate used to calculate interest on base rate loans will be 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 ranges from 0.625% to 1.50% for base rate loans and 1.625% to 2.50% for Eurodollar loans.

Regency pays (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. In December 2011, Regency amended its credit facility to allow for additional investments in its joint ventures.

As of December 31, 2013, Regency had a balance outstanding of $510 million under the Regency Credit Facility in revolving credit loans and approximately $14 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2013, which is reduced by any letters of credit, was approximately $676 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 2.17%.

Southern Union Credit Facilities

Proceeds from the SUGS Contribution were used to repay borrowings under the Southern Union Credit Facility and the facility was terminated during 2013.

Sunoco Logistics Credit Facilities

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

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

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

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The ETE Term Loan Facility and ETE Revolving Credit Facility contain customary representations, warranties, covenants, and events of default, including a change of control event of default and limitations on incurrence of liens, new lines of business, merger, transactions with affiliates and restrictive agreements.

The ETE Term Loan Facility and ETE Revolving Credit Facility contain financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to EBITDA (as defined in the agreements) of the Parent Company of not more than 6.0 to 1, with a permitted increase to 7 to 1 during a specified acquisition period following the close of a specified acquisition; and

- EBITDA to interest expense of not less than 1.5 to 1.

Covenants Related to ETP Credit Agreements

The agreements relating to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) ETP's and certain of ETP'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 ETP 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.

Covenants Related to Regency Credit Agreements

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 many of the foregoing covenants. The Regency Credit Facility contains 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 contains 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.

Covenants Related to Southern Union Credit Agreements

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

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

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

Covenants Related to Sunoco Logistics

Sunoco Logistics' $350 million and $200 million credit facilities contain various covenants limiting its ability to incur indebtedness; grant certain liens; make certain loans, acquisitions and investments; make any material change to the nature of its business; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The credit facilities also limit Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated EBITDA ratio, as defined in the underlying credit agreements, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

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

Compliance with our Covenants

We are required to assess compliance quarterly and were in compliance with all requirements, limitations, and covenants relating to ETE's and its subsidiaries' debt agreements as of December 31, 2013.

Each of the agreements referred to above are incorporated herein by reference to our, ETP's and Regency's reports previously filed with the SEC under the Exchange Act. See "Item 1. Business – SEC Reporting."

Contingent Residual Support Agreement – AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6 to 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 with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt.

PEPL Holdings Guarantee of Collection

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

Contractual Obligations

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

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 22,898	$ 812	$ 1,422	$ 3,196	$ 17,468
Interest on long-term debt[1]	15,921	1,263	2,340	2,154	10,164
Payments on derivatives	74	35	39	—	—
Purchase commitments[2]	25,704	12,389	7,883	2,175	3,257
Transportation, natural gas storage and fractionation contracts	122	33	48	37	4
Operating lease obligations	813	83	153	123	454
Distributions and redemption of preferred units of a subsidiary[3]	100	3	7	7	83
Other	246	77	89	56	24
Total[4]	$ 65,878	$ 14,695	$ 11,981	$ 7,748	$ 31,454

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2013. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2013. To the extent interest rates change, our contractual obligation 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, 2013 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated

future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated. Approximately $5.72 billion of total purchase commitments relate to production from PES.

(3) Assumes the outstanding Regency Preferred Units are redeemed for cash on September 2, 2029.

(4) Excludes net non-current deferred tax liabilities of $3.87 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by the Parent Company

Under the Parent Company Partnership Agreement, the Parent Company will distribute all of its Available Cash, as defined, within 50 days following the end of each fiscal quarter. Available cash generally means, with respect to any quarter, all cash on hand at the end of such quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner that is necessary or appropriate to provide for future cash requirements.

Distributions paid are as follows:

Quarter Ended	Record Date	Payment Date	Rate	
Year Ended December 31, 2013	November 4, 2013	November 19, 2013	$	0.33625
	August 5, 2013	August 19, 2013		0.32750
	May 6, 2013	May 17, 2013		0.32250
	February 7, 2013	February 19, 2013		0.31750
Year Ended December 31, 2012	November 6, 2012	November 16, 2012	$	0.31250
	August 6, 2012	August 17, 2012		0.31250
	May 4, 2012	May 18, 2012		0.31250
	February 7, 2012	February 17, 2012		0.31250
Year Ended December 31, 2011	November 4, 2011	November 18, 2011	$	0.31250
	August 5, 2011	August 19, 2011		0.31250
	May 6, 2011	May 19, 2011		0.28000
	February 7, 2011	February 18, 2011		0.27000

On January 28, 2014, the Parent Company declared a cash distribution for the three months ended December 31, 2013 of $0.34625 per Common Unit, or $1.39 annualized. We paid this distribution on February 19, 2014 to Unitholders of record at the close of business on February 7, 2014.

The total amounts of distributions declared during the periods presented (all from Available Cash from the Parent Company's operating surplus and are shown in the period to which they relate) are as follows:

	Years Ended December 31,		
	2013	2012	2011
Limited Partners	$ 748	$ 703	$ 543
General Partner interest	2	1	2
Total Parent Company distributions	$ 750	$ 704	$ 545

Cash Distributions Received by the Parent Company

The Parent Company's cash available for distributions is primarily generated from its direct and indirect interests in ETP and Regency. Effective with the Parent Company's acquisition of 100% of Trunkline LNG on February 19, 2014, Trunkline LNG's wholly-owned subsidiaries also contribute to the Parent Company's cash available for distributions. Subsequent to that transaction, our interests in ETP and Regency consist of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	30.8 (1)	26.3
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

(1) On February 19, 2014, ETE closed on its acquisition of TLNG from ETP in exchange for the redemption by ETP of 18.71 million ETP common units held by ETE. This amount represents the ETP common units owned through wholly-owned subsidiaries subsequent to the transaction.

As the holder of ETP's and Regency's IDRs, the Parent Company is entitled to an increasing share of ETP's and Regency's total distributions above certain target levels. The following table summarizes the target levels (as a percentage of total distributions on common units, IDRs and the general partner interest). The percentage reflected in the table includes only the percentage related to the IDRs and excludes distributions to which the Parent Company would also be entitled through its direct or indirect ownership of (i) ETP's general partner interest, Class H units and a portion of the outstanding ETP common units and (ii) Regency's general partner interest and a portion of the outstanding Regency common units.

	Percentage of Total Distributions to IDRs	Quarterly Distribution Rate Target Amounts	
		ETP	Regency
Minimum quarterly distribution	—%	$0.25	$0.35
First target distribution	—%	$0.25 to $0.275	$0.35 to $0.4025
Second target distribution	13%	$0.275 to $0.3175	$0.4025 to $0.4375
Third target distribution	23%	$0.3175 to $0.4125	$0.4375 to $0.5250
Fourth target distribution	48%	Above $0.4125	Above $0.5250

The total amount of distributions the Parent Company received from ETP and Regency relating to its limited partner interests, general partner interest and incentive distributions (shown in the period to which they relate) for the periods ended as noted below is as follows:

	Years Ended December 31,		
	2013	2012	2011
Distributions from ETP:			
Limited Partners	$ 268	$ 180	$ 180
Class H Units held by ETE Holdings	105	—	—
General Partner interest	20	20	20
Incentive distributions	701	529	422
Incentive distribution relinquishments related to previous transactions	(199)	(90)	—
Total distributions from ETP	895	639	622
Distributions from Regency:			
Limited Partners	48	48	48
General Partner interest	5	5	5
Incentive distributions	12	8	6
Incentive distribution relinquishments related to previous transaction	(3)	—	—
Total distributions from Regency	62	61	59
Total distributions received from subsidiaries	$ 957	$ 700	$ 681

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

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

- In conjunction with ETP’s Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.
- As discussed in Note 3, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.
- In conjunction with Southern Union’s contributions of SUGS to Regency, ETE agreed to relinquish incentive distributions on the 31.4 million Regency Common Units issued for twenty-four months subsequent to the transaction closing.

In addition, the incremental distributions on the Class H Units were intended to offset a portion of the incentive distribution subsidies previously granted by ETE to ETP. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the incremental distributions on the ETP Class H Units in order to ensure that the net impact of the incentive distribution subsidies (a portion of which is variable) and the incremental distributions on the ETP Class H Units are fixed amounts for each quarter for which the incentive distribution subsidies and incremental distributions on the ETP Class H Units are in effect.

In connection with the transfer of Trunkline LNG on February 19, 2014, ETE agreed to relinquish incentive distributions of $50 million, $50 million, $45 million, and $35 million during the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

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

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$ 26.5	$ 26.5	$ 26.5	$ 26.5	$ 106.0
2015	12.5	12.5	13.0	13.0	51.0
2016	18.0	18.0	18.0	18.0	72.0
2017	12.5	12.5	12.5	12.5	50.0
2018	11.25	11.25	11.25	11.25	45.0
2019	8.75	8.75	8.75	8.75	35.0

Cash Distributions Paid by ETP

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

Distributions paid by ETP are summarized as follows:

	Record Date	Payment Date	Rate
Year Ended December 31, 2013	November 4, 2013	November 14, 2013	$ 0.90500
	August 5, 2013	August 14, 2013	0.89375
	May 6, 2013	May 15, 2013	0.89375
	February 7, 2013	February 14, 2013	0.89375
Year Ended December 31, 2012	November 6, 2012	November 14, 2012	$ 0.89375
	August 6, 2012	August 14, 2012	0.89375
	May 4, 2012	May 15, 2012	0.89375
	February 7, 2012	February 14, 2012	0.89375
Year Ended December 31, 2011	November 4, 2011	November 14, 2011	$ 0.89375
	August 5, 2011	August 15, 2011	0.89375
	May 6, 2011	May 16, 2011	0.89375
	February 7, 2011	February 14, 2011	0.89375

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

The total amounts of distributions declared during the periods presented (all from Available Cash from ETP's operating surplus and are shown in the period to which they relate) are as follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Limited Partners:			
Common Units	$ 1,273	$ 963	$ 762
Class H Units	105	—	—
General Partner interest	20	20	20
IDRs	701	529	422
IDR relinquishments related to previous transactions [(1)]	(199)	(90)	—
Total ETP distributions	$ 1,900	$ 1,422	$ 1,204

(1) In connection with certain prior transactions, the Parent Company has agreed to relinquish its rights to specified amounts of distribution payments for a limited period of time. See discussion above under "Cash Distributions Received by the Parent Company."

Cash Distributions Paid by Sunoco Logistics

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

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

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

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

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

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

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

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 paid by Regency since the date of acquisition are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate	
September 30, 2013	November 4, 2013	November 14, 2013	$	0.470
June 30, 2013	August 5, 2013	August 14, 2013		0.465
March 31, 2013	May 6, 2013	May 13, 2013		0.460
December 31, 2012	February 7, 2013	February 14, 2013		0.460
September 30, 2012	November 6, 2012	November 14, 2012	$	0.460
June 30, 2012	August 6, 2012	August 14, 2012		0.460
March 31, 2012	May 7, 2012	May 14, 2012		0.460
December 31, 2011	February 6, 2012	February 13, 2012		0.460
September 30, 2011	November 7, 2011	November 14, 2011	$	0.455
June 30, 2011	August 5, 2011	August 12, 2011		0.450
March 31, 2011	May 6, 2011	May 13, 2011		0.445
December 31, 2010	February 7, 2011	February 14, 2011		0.445

On January 28, 2014, Regency declared a cash distribution for the three months ended December 31, 2013 of $0.475 per Regency Common Unit, or $1.90 annualized. Regency paid this distribution on February 14, 2014 to Regency Unitholders of record at the close of business on February 7, 2014.

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

	Years Ended December 31,	
	2013	2012
Limited Partners	$ 390	$ 314
General Partner Interest	5	5
Incentive Distribution Rights	12	8
IDR relinquishments related to previous transactions [1]	(3)	—
Total Regency distributions	$ 407	$ 327

(1) In connection with certain prior transactions, the Parent Company has agreed to relinquish its rights to specified amounts of distribution payments for a limited period of time. See discussion above under "Cash Distributions Received by the Parent Company."

New Accounting Standards

None.

Estimates and Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption (when early adoption is permitted), 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 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 operating results estimated for the year ended December 31, 2013 represent the actual results in all material respects.

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

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.

The results of ETP's intrastate transportation and storage and interstate transportation operations are determined primarily by the amount of capacity ETP's customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, ETP 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.

ETP's intrastate transportation and storage operations also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, ETP purchases natural gas from the market, including purchases from the midstream marketing operations, and from producers at the wellhead.

In addition, ETP's intrastate transportation and storage operations generate revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. ETP also engages in natural gas storage transactions in which ETP seeks to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. ETP purchases physical natural gas and then sells financial contracts at a price sufficient to cover ETP's carrying costs and provide for a gross profit margin. ETP expects 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, ETP 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 ETP's midstream operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through ETP's pipeline and gathering systems and the level of natural gas and NGL prices. ETP generates midstream revenues and gross margins principally under fee-based or other arrangements in which ETP receives 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 ETP's systems and is not directly dependent on commodity prices.

ETP also utilizes other types of arrangements in ETP's midstream operations, 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 ETP gathers natural gas from the producer, processes the natural gas and sells the resulting NGLs to third parties at market prices. In many cases, ETP provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of ETP's contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. ETP's 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.

ETP conducts marketing activities in which ETP markets the natural gas that flows through ETP's assets, referred to as on-system gas. ETP also attracts other customers by marketing volumes of natural gas that do not move through ETP's assets, referred to as off-system gas. For both on-system and off-system gas, ETP purchases natural gas from natural gas producers and other supply points and sells 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.

ETP has a risk management policy that provides for oversight over ETP's marketing activities. These activities are monitored independently by ETP's risk management function and must take place within predefined limits and authorizations. As a result of ETP's 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. ETP attempts 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 ETP's risk management policy.

ETP injects and holds 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. ETP uses financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, ETP locks 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 ETP designates the related financial contract as a fair value hedge for accounting purposes, ETP values the hedged natural gas inventory at current spot market prices along with the financial derivative ETP uses 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, ETP will record unrealized gains or lower unrealized losses. If the spread widens, ETP will record unrealized losses or lower unrealized gains. Typically, as ETP enters the winter months, the spread converges so that ETP recognizes in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

ETP's 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 ETP's 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.

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

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.

Trunkline LNG's revenues from storage and re-gasification of natural gas are based on capacity reservation charges and, to a lesser extent, commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by the customers and recognized monthly. Revenues from commodity usage charges are also recognized monthly and represent the recovery of electric power charges at Trunkline LNG's terminal.

Regulatory Assets and Liabilities. Certain of our subsidiaries are subject to regulation by certain state and federal authorities and have accounting policies that conform to FASB Accounting Standards Codification ("ASC") Topic 980, *Regulated Operations*, which is in accordance with 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. ETP and Regency utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit their exposure to margin fluctuations in natural gas, NGL and refined products. These contracts consist primarily of commodity futures and swaps. In addition, prior to ETP's contribution of its retail propane activities to AmeriGas, ETP used derivatives to limit its exposure to propane market prices.

If ETP or Regency 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 ETP or Regency designate a hedging relationship as a fair value hedge, they record the changes in fair value of the hedged asset or liability in cost of products sold in the 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.

ETP and Regency 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, interest rate derivatives, the Preferred Units and embedded derivatives in the Regency Preferred Units 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 utilizes significant unobservable inputs. Level 3 inputs are unobservable. Derivatives related to the Regency Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are considered Level 3. The fair value of the Preferred Units as of December 31, 2012 was based predominantly on an income approach model and is also considered Level 3 as of December 31, 2012. See further information on our fair value assets and liabilities in Note 2 of our consolidated financial statements.

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

In order to test for recoverability when performing a quantitative impairment test, we must make estimates of projected cash flows related to the asset, which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset's existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of natural gas, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other companies, including major energy producers. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

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

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

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, ETP capitalizes certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the consolidated statement of operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful lives ranging from 1 to 99 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful lives of our property, plant and equipment.

Asset Retirement Obligation. We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

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

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

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

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

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

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

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

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

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

For more information on our litigation and contingencies, see Note 11 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Date" 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. ETP has 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, ETP accrues 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. ETP's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded.

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

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

Deferred Income Taxes. ETE recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards ("NOLs") and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal tax alternative minimum tax credit carryforwards totaling $217 million have been included in ETE's consolidated balance sheet as of December 31, 2013. All of the deferred income tax assets except $3 million attributable to state and federal NOL benefits expire before 2032 as more fully described below. The state NOL carryforward benefits of $101 million (net of federal benefit) begin to expire in 2013 with a substantial portion expiring between 2029 and 2032. The federal NOLs of $216 million ($76 million in benefits) will expire in 2032, while the $40 million of the federal tax alternative minimum tax credit carryforwards have no expiration date. We have determined that a valuation allowance totaling $74 million (net of federal income tax effects) is required for the state NOLs at December 31, 2013 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "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 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 subsidiaries' pipelines and gathering systems;
- the level of throughput in our subsidiaries' processing and treating facilities;
- the fees our subsidiaries charge and the margins they realize for their 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 subsidiaries' 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 subsidiaries pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our subsidiaries liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our subsidiaries' customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our subsidiaries' internal growth projects, such as our subsidiaries' construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our subsidiaries' 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 subsidiaries' 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 our subsidiaries own less than a controlling interests, including risks related to management actions at such entities that our subsidiaries 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.

SIGNATURE

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 EQUITY, L.P.

By: LE GP, LLC, its General Partner

Date: July 10, 2014

By: /s/ Jamie Welch

Jamie Welch

Group Chief Financial Officer (duly authorized to sign on behalf of the registrant)

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
INDEX TO FINANCIAL STATEMENTS

Energy Transfer Equity, L.P. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Equity, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Equity, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, 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, 2013. 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 consolidated financial statements of Sunoco Logistics Partners L.P., a consolidated subsidiary, as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, which statements reflect total assets constituting 21 percent of consolidated total assets as of December 31, 2012, and total revenues of 19 percent of consolidated total revenues for the year then ended. 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. as of December 31, 2012 and 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 report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 15, the accompanying consolidated financial statements have been adjusted to reflect a change in the Partnership's reportable segments.

/s/ GRANT THORNTON LLP

Dallas, Texas

February 27, 2014 (except for Note 15, as to which the date is July 10, 2014)

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

	December 31,	
	2013	2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 590	$ 372
Accounts receivable, net	3,658	3,057
Accounts receivable from related companies	63	71
Inventories	1,807	1,522
Exchanges receivable	67	55
Price risk management assets	39	25
Current assets held for sale	—	184
Other current assets	312	311
Total current assets	6,536	5,597
PROPERTY, PLANT AND EQUIPMENT	33,917	30,388
ACCUMULATED DEPRECIATION	(3,235)	(2,104)
	30,682	28,284
NON-CURRENT ASSETS HELD FOR SALE	—	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,014	4,737
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	18	43
GOODWILL	5,894	6,434
INTANGIBLE ASSETS, net	2,264	2,291
OTHER NON-CURRENT ASSETS, net	922	533
Total assets	$ 50,330	$ 48,904

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

	December 31,	
	2013	2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,834	$ 3,107
Accounts payable to related companies	14	15
Exchanges payable	284	156

Price risk management liabilities	53	115
Accrued and other current liabilities	1,678	1,754
Current maturities of long-term debt	637	613
Current liabilities held for sale	—	85
Total current liabilities	6,500	5,845
NON-CURRENT LIABILITIES HELD FOR SALE	—	142
LONG-TERM DEBT, less current maturities	22,562	21,440
DEFERRED INCOME TAXES	3,865	3,566
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	73	162
PREFERRED UNITS (Note 7)	—	331
OTHER NON-CURRENT LIABILITIES	1,019	995
COMMITMENTS AND CONTINGENCIES (Note 11)		
PREFERRED UNITS OF SUBSIDIARY (Note 7)	32	73
EQUITY:		
General Partner	(3)	—
Limited Partners:		
Common Unitholders (559,923,300 and 559,911,216 units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively)	1,066	2,125
Class D Units (1,540,000 units authorized, issued and outstanding at December 31, 2013)	6	—
Accumulated other comprehensive income (loss)	9	(12)
Total partners' capital	1,078	2,113
Noncontrolling interest	15,201	14,237
Total equity	16,279	16,350
Total liabilities and equity	$ 50,330	$ 48,904

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

	Years Ended December 31,		
	2013	2012	2011
REVENUES:			
Natural gas sales	$ 3,842	$ 2,705	$ 2,982
NGL sales	3,618	2,253	1,716
Crude sales	15,477	2,872	—
Gathering, transportation and other fees	3,097	2,386	1,819
Refined product sales	18,479	5,299	—
Other	3,822	1,449	1,673
Total revenues	48,335	16,964	8,190
COSTS AND EXPENSES:			
Cost of products sold	42,554	13,088	5,169
Operating expenses	1,642	1,116	945
Depreciation and amortization	1,313	871	586
Selling, general and administrative	586	529	253
Goodwill impairment	689	—	—
Total costs and expenses	46,784	15,604	6,953
OPERATING INCOME	1,551	1,360	1,237
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(1,221)	(1,018)	(740)
Bridge loan related fees	—	(62)	—
Equity in earnings of unconsolidated affiliates	236	212	117

Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Losses on extinguishments of debt	(162)	(123)	—
Gains (losses) on interest rate derivatives	53	(19)	(78)
Impairments of investments in affiliates	—	—	(5)
Non-operating environmental remediation	(168)	—	—
Other, net	(1)	30	17
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	375	1,437	548
Income tax expense from continuing operations	93	54	17
INCOME FROM CONTINUING OPERATIONS	282	1,383	531
Income (loss) from discontinued operations	33	(109)	(3)
NET INCOME	315	1,274	528
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	119	970	218
NET INCOME ATTRIBUTABLE TO PARTNERS	196	304	310
GENERAL PARTNER’S INTEREST IN NET INCOME	—	2	1
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 196	$ 302	$ 309
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$ 0.33	$ 0.59	$ 0.69
Diluted	$ 0.33	$ 0.59	$ 0.69
NET INCOME PER LIMITED PARTNER UNIT:			
Basic	$ 0.35	$ 0.57	$ 0.69
Diluted	$ 0.35	$ 0.57	$ 0.69

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

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 315	$ 1,274	$ 528
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(4)	(17)	(19)
Change in value of derivative instruments accounted for as cash flow hedges	(1)	12	7
Change in value of available-for-sale securities	2	—	(1)
Actuarial gain (loss) relating to pension and other postretirement benefits	66	(10)	—
Foreign currency translation adjustment	(1)	—	—
Change in other comprehensive income from equity investments	17	(9)	—
	79	(24)	(13)
Comprehensive income	394	1,250	515
Less: Comprehensive income attributable to noncontrolling interest	181	959	209
Comprehensive income attributable to partners	$ 213	$ 291	$ 306

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

	General Partner	Common Unitholders	Class D Units	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total
Balance, December 31, 2010	$ 1	$ 114	$ —	$ 5	$ 6,127	$ 6,247
Distributions to partners	(2)	(524)	—	—	—	(526)
Distributions to noncontrolling interest	—	—	—	—	(779)	(779)
Subsidiary equity offerings, net of issue costs	—	153	—	—	1,750	1,903
Subsidiary units issued in acquisition	—	—	—	—	3	3
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	—	—	33	34
Other, net	—	(1)	—	—	(8)	(9)
Other comprehensive loss, net of tax	—	—	—	(4)	(9)	(13)
Net income	1	309	—	—	218	528
Balance, December 31, 2011	—	52	—	1	7,335	7,388
Distributions to partners	(2)	(664)	—	—	—	(666)
Distributions to noncontrolling interest	—	—	—	—	(1,017)	(1,017)
Units issued in Southern Union Merger (See Note 3)	—	2,354	—	—	—	2,354
Subsidiary equity offerings, net of issue costs	—	33	—	—	1,070	1,103
Subsidiary units issued in acquisition	—	47	—	—	2,248	2,295
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	—	—	31	32
Capital contributions received from noncontrolling interest	—	—	—	—	42	42
Holdco Transaction (see Note 3)	—	—	—	—	3,580	3,580
Other, net	—	—	—	—	(11)	(11)
Other comprehensive loss, net of tax	—	—	—	(13)	(11)	(24)
Net income	2	302	—	—	970	1,274
Balance, December 31, 2012	—	2,125	—	(12)	14,237	16,350
Distributions to partners	(2)	(731)	—	—	—	(733)
Distributions to noncontrolling interest	—	—	—	—	(1,428)	(1,428)
Subsidiary equity offerings, net of issue costs	—	122	—	—	1,637	1,759
Subsidiary units issued in acquisition	(1)	(506)	—	—	507	—
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	6	—	47	54
Capital contributions received from noncontrolling interest	—	—	—	—	18	18
Other, net	—	—	—	4	(39)	(35)
Conversion of Regency Preferred Units for Regency Common Units	—	—	—	—	41	41
Deemed distribution related to SUGS Transaction	—	(141)	—	—	—	(141)
Other comprehensive income, net of tax	—	—	—	17	62	79
Net income	—	196	—	—	119	315
Balance, December 31, 2013	$ (3)	$ 1,066	$ 6	$ 9	$ 15,201	$ 16,279

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

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			

Net income	$ 315	$ 1,274	$ 528
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	1,313	871	586
Deferred income taxes	43	51	1
Gain on curtailment of other postretirement benefit plans	—	(15)	—
Amortization included in interest expense	(55)	(13)	20
Bridge loan related fees	—	62	—
Non-cash compensation expense	61	47	42
Gain on deconsolidation of Propane Business	—	(1,057)	—
Gain on sale of AmeriGas common units	(87)	—	—
Goodwill impairment	689	—	—
Losses on extinguishments of debt	162	123	—
Losses on disposal of assets	2	4	1
Equity in earnings of unconsolidated affiliates	(236)	(212)	(117)
Distributions from unconsolidated affiliates	313	208	126
LIFO valuation adjustments	(3)	75	—
Other non-cash	51	211	33
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(149)	(551)	158
Net cash provided by operating activities	2,419	1,078	1,378
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Southern Union Merger, net of cash received (See Note 3)	—	(2,972)	—
Cash proceeds from contribution and sale of propane operations	—	1,443	—
Cash proceeds from the sale of the MGE and NEG assets (See Note 3)	1,008	—	—
Cash proceeds from the sale of AmeriGas common units	346	—	—
Cash paid for all other acquisitions	(405)	(10)	(1,972)
Proceeds from the sale of other assets	89	251	33
Capital expenditures (excluding allowance for equity funds used during construction)	(3,505)	(3,271)	(1,810)
Contributions in aid of construction costs	52	35	25
Contributions to unconsolidated affiliates	(3)	(37)	(222)
Distributions from unconsolidated affiliates in excess of cumulative earnings	419	189	72
Restricted cash	(348)	5	—
Other	—	171	—
Net cash used in investing activities	(2,347)	(4,196)	(3,874)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	12,934	12,870	8,262
Repayments of long-term debt	(11,951)	(8,848)	(6,264)
Subsidiary equity offerings, net of issue costs	1,759	1,103	1,903
Distributions to partners	(733)	(666)	(526)
Distributions to noncontrolling interests	(1,428)	(1,017)	(779)
Debt issuance costs	(87)	(112)	(53)
Capital contributions received from noncontrolling interest	18	42	—
Redemption of Preferred Units	(340)	—	—
Other, net	(26)	(8)	(7)
Net cash provided by financing activities	146	3,364	2,536
INCREASE IN CASH AND CASH EQUIVALENTS	218	246	40
CASH AND CASH EQUIVALENTS, beginning of period	372	126	86
CASH AND CASH EQUIVALENTS, end of period	$ 590	$ 372	$ 126

ENERGY TRANSFER EQUITY, 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:

Financial Statement Presentation

The consolidated financial statements of Energy Transfer Equity, L.P. (the “Partnership,” “we” or “ETE”) presented herein for the years ended December 31, 2013, 2012 and 2011, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and limited partnerships, which we control as the general partner or owner of the general partner. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through the date the financial statements were issued.

As discussed in Note 8, in January 2014, the Partnership completed a two-for-one split of ETE Common Units. All references to unit and per unit amounts in the consolidated financial statements and in these notes to the consolidated financial statements have been adjusted to reflect the effect of the unit split for all periods presented.

On March 26, 2012, we acquired all of the outstanding shares of Southern Union. On October 5, 2012, ETP completed the Sunoco Merger and we and ETP also completed the Holdco Transaction at that time. On April 30, 2013, ETP acquired our 60% interest in Holdco. See Note 3 for more information regarding these transactions.

At December 31, 2013, our equity interests in Regency and ETP consisted of 100% of the respective general partner interest and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49.6	26.3
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

The consolidated financial statements of ETE presented herein include the results of operations of:

- the Parent Company;
- our controlled subsidiaries, ETP and Regency (see description of their respective operations below under “Business Operations”);
- ETP’s and Regency’s consolidated subsidiaries and our wholly-owned subsidiaries that own the general partner and IDR interests in ETP and Regency.

As a result of the Southern Union Merger in March 2012 and the Holdco Transaction in October 2012, the periods presented herein do not include activities from Southern Union or Sunoco prior to the consummation of the respective mergers and/or transactions.

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

Certain prior period amounts have been reclassified to conform to the 2013 presentation. These reclassifications had no impact on net income or total equity. In October 2012, ETP sold Canyon and the results of continuing operations of Canyon have been reclassified to income (loss) from discontinued operations and the prior year amounts have been adjusted to present Canyon’s operations as discontinued operations. Canyon was previously included in ETP’s midstream operations. In 2013, Southern Union sold its distribution operations. The results of operations of the distribution operations have been reported as income (loss) from discontinued operations. The assets and liabilities of the disposal group have been reported as assets and liabilities held for sale as of December 31, 2012.

Unless the context requires otherwise, references to “we,” “us,” “our,” the “Partnership” and “ETE” mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, ETP GP, ETP LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Sunoco Logistics and Holdco. References to the “Parent Company” mean Energy Transfer Equity, L.P. on a stand-alone basis.

Business Operations

The Parent Company’s principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency. The Parent Company’s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. Parent Company-only assets are not available to satisfy the debts and other obligations of ETE’s subsidiaries. In order to understand the financial condition of the Parent Company on a stand-alone basis, see Note 17 for stand-alone financial information apart from that of the consolidated partnership information included herein.

Our activities are primarily conducted through our operating subsidiaries as follows:

- ETP’s operations are conducted through the following subsidiaries:
  - 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 its 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 its Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star and also owns a convenience store operator with approximately 300 company-owned and dealer locations.
  - 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 Corp., 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.

- Sunoco Logistics is a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products and crude oil pipelines, terminalling and storage assets, and refined products and crude oil acquisition and marketing assets.
- Holdco is a Delaware limited liability company that indirectly owns Panhandle and Sunoco. As discussed in Note 3, ETP acquired ETE's 60% interest in Holdco on April 30, 2013. Panhandle and Sunoco 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, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interests in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. Also, as discussed in Note 3, Southern Union completed its sale of the assets of MGE and NEG in 2013. Additionally, 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 owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States.
- Regency is a publicly traded partnership engaged in the gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. 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. Its assets are located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, New Mexico and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma. Regency also holds a 30% interest in Lone Star.
- Trunkline LNG operates a LNG import terminal, which has approximately 9.0 bcf of above ground LNG storage capacity and re-gasification facilities on Louisiana's Gulf Coast near Lake Charles, Louisiana. Trunkline LNG is engaged in interstate commerce and is subject to the rules, regulations and accounting requirements of the FERC.

As discussed in Note 15 to our consolidated financial statements, subsequent to the acquisition of Trunkline LNG in February 2014, our reportable segments changed and currently reflect the following reportable business segments: Investment in ETP; Investment in Regency; Investment in Trunkline LNG; and Corporate and 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 natural gas and NGL related 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 values and results could differ from those estimates.

Revenue Recognition

Our segments are engaged in multiple revenue-generating activities. To the extent that those activities are similar among our segments, revenue recognition policies are similar. Below is a description of revenue recognition policies for significant revenue-generating activities within our segments.

Investment in ETP

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.

The results of ETP's intrastate transportation and storage and interstate transportation and storage operations are determined primarily by the amount of capacity customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, 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.

ETP's intrastate transportation and storage operations also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, ETP purchases natural gas from the market, including purchases from ETP's marketing operations, and from producers at the wellhead.

In addition, ETP's intrastate transportation and storage operations generate revenues and margin from fees charged for storing customers' working natural gas in ETP's storage facilities. ETP also engages in natural gas storage transactions in which ETP seeks to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. ETP purchases physical natural gas and then sells financial contracts at a price sufficient to cover ETP's carrying costs and provide for a gross profit margin. ETP expects 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, ETP 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 ETP operate, competitive factors in the energy industry, and other issues.

Results from ETP's midstream operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through ETP's pipeline and gathering systems and the level of natural gas and NGL prices. ETP generates midstream revenues and gross margins principally under fee-based or other arrangements in which ETP receives 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 ETP's systems and is not directly dependent on commodity prices.

ETP also utilizes other types of arrangements in ETP's midstream operations, 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 ETP gathers and processes natural gas on behalf of producers, sells the resulting residue gas and NGL volumes at market prices and remits to producers an agreed upon percentage of the proceeds based on an index price, (iii) keep-whole arrangements where ETP gathers natural gas from the producer, processes the natural gas and sells 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 ETP's plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing objectives. In many cases, ETP provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of ETP's contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. ETP's 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 ETP's 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.

ETP conducts marketing activities in which ETP markets the natural gas that flows through ETP's assets, referred to as on-system gas. ETP also attracts other customers by marketing volumes of natural gas that do not move through ETP's assets, referred to as off-system gas. For both on-system and off-system gas, ETP purchases natural gas from natural gas producers and other supply points and sells 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.

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

Investment in Regency

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 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 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.

Investment in Trunkline LNG

Trunkline LNG's revenues from storage and re-gasification of natural gas are based on capacity reservation charges and, to a lesser extent, commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by the customers and recognized monthly. Revenues from commodity usage charges are also recognized monthly and represent the recovery of electric power charges at Trunkline LNG's terminal.

Regulatory Accounting – Regulatory Assets and Liabilities

ETP's interstate transportation and storage operations are subject to regulation by certain state and federal authorities and certain subsidiaries in those operations 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 ETP's 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, ETP ceases 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.

Southern Union recorded regulatory assets with respect to its distribution operations. At December 31, 2012, there were $123 million of regulatory assets included in our consolidated balance sheet as non-current assets held for sale. Southern Union's distribution operations were sold in 2013.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the NGA and NGPA, 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 which are subject to an insignificant risk of changes in value.

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

The net change in operating assets and liabilities (net of effects of acquisitions, dispositions and deconsolidation) included in cash flows from operating activities was comprised as follows:

	Years Ended December 31,		
	2013	2012	2011
Accounts receivable	$ (556)	$ 267	$ 6
Accounts receivable from related companies	64	(9)	(24)
Inventories	(254)	(258)	51
Exchanges receivable	(8)	14	1
Other current assets	(81)	597	(51)
Other non-current assets, net	(23)	(129)	7
Accounts payable	541	(989)	21
Accounts payable to related companies	(140)	92	6
Exchanges payable	128	—	2
Accrued and other current liabilities	192	(159)	84
Other non-current liabilities	147	26	—
Price risk management assets and liabilities, net	(159)	(3)	55
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (149)	$ (551)	$ 158

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

	Years Ended December 31,		
	2013	2012	2011
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 226	$ 420	$ 226
Net gains (losses) from subsidiary common unit transactions	$ (384)	$ 80	$ 153
AmeriGas limited partner interest received in Propane Contribution (see Note 4)	$ —	$ 1,123	$ —
NON-CASH FINANCING ACTIVITIES:			
Issuance of Common Units in connection with Southern Union Merger (see Note 3)	$ —	$ 2,354	$ —
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ —	$ 6,658	$ 4
Subsidiary issuance of Common Units in connection with certain acquisitions	$ —	$ 2,295	$ 3
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,256	$ 997	$ 728
Cash paid for income taxes	$ 58	$ 23	$ 27

Accounts Receivable

Our subsidiaries assess the credit risk of their customers. Certain of our subsidiaries deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guarantee prepayment, master setoff agreement or collateral). Management reviews accounts receivable and an allowance for doubtful accounts is determined based on the overall creditworthiness of customers, historical write-off experience, general and specific economic trends, and specific identification.

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,

	2013	2012
Natural gas and NGLs	$ 523	$ 338
Crude oil	488	418
Refined products	597	572
Appliances, parts and fittings and other	199	194
Total inventories	$ 1,807	$ 1,522

ETP utilizes commodity derivatives to manage price volatility associated with its natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and in 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,	
	2013	2012
Deposits paid to vendors	$ 49	$ 41
Prepaid and other	263	270
Total other current assets	$ 312	$ 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. Natural gas and NGLs used to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Additionally, our subsidiaries 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 and our subsidiaries 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. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $128 million during the year ended December 31, 2012.

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 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,	
	2013	2012
Land and improvements	$ 881	$ 553
Buildings and improvements (5 to 45 years)	939	692
Pipelines and equipment (5 to 83 years)	21,494	19,505
Natural gas and NGL storage facilities (5 to 46 years)	1,083	1,057
Bulk storage, equipment and facilities (2 to 83 years)	1,933	1,745
Tanks and other equipment (5 to 40 years)	1,697	1,194
Retail equipment (3 to 99 years)	450	258
Vehicles (1 to 25 years)	156	154
Right of way (20 to 83 years)	2,190	2,134
Furniture and fixtures (2 to 25 years)	51	67
Linepack	118	118
Pad gas	52	58
Other (1 to 48 years)	708	880
Construction work-in-process	2,165	1,973
	33,917	30,388
Less – Accumulated depreciation	(3,235)	(2,104)
Property, plant and equipment, net	$ 30,682	$ 28,284

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

	Years Ended December 31,		
	2013	2012	2011
Depreciation expense [1]	$ 1,128	$ 801	$ 531
Capitalized interest, excluding AFUDC	$ 43	$ 99	$ 13

(1) Depreciation expense amounts have been adjusted by $26 million for the year ended December 31, 2011 to present Canyon's operations as discontinued operations.

Advances to and Investments in Affiliates

Certain of our subsidiaries 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 reporting units within ETP's intrastate transportation and storage and midstream operations and during the fourth quarter for reporting units within ETP's interstate transportation and storage and NGL transportation and services operations and all others, including all of Regency's reporting units.

Changes in the carrying amount of goodwill were as follows:

	Investment in ETP	Investment in Regency	Corporate, Other and Eliminations	Total
Balance, December 31, 2011	$ 1,220	$ 790	$ 29	$ 2,039
Goodwill acquired [1]	5,138	337	(328)	5,147
Goodwill sold in deconsolidation of ETP Propane Business	(619)	—	—	(619)
Goodwill allocated to the disposal group	(133)	—	—	(133)
Balance, December 31, 2012	5,606	1,127	(299)	6,434
Goodwill acquired	156	—	—	156
Deconsolidation of SUGS [1]	(337)	—	337	—
Goodwill impairment	(689)	—	—	(689)
Other	(7)	—	—	(7)
Balance, December 31, 2013	$ 4,729	$ 1,127	$ 38	$ 5,894

(1) As discussed in Note 3, Regency completed its acquisition of SUGS on April 30, 2013 which was a transaction between entities under common control. Therefore, the investment in Regency segment amounts have been retrospectively adjusted to reflect SUGS beginning March 26, 2012. Therefore, the December 31, 2012 goodwill balance includes goodwill attributable to SUGS of $337 million in both segments that was correspondingly included in the elimination column. ETP deconsolidated SUGS on April 30, 2013.

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 $4.40 billion during the year ended December 31, 2012 primarily due to the Southern Union and Sunoco Mergers where we recorded goodwill of $2.50 billion and $2.64 billion, respectively. We recorded a net decrease in goodwill of $540 million during the year ended December 31, 2013 primarily due to Trunkline LNG's goodwill impairment of $689 million (see below). These decreases were offset by additional goodwill of $156 million from acquisitions in 2013. The additional goodwill recorded during the years ended December 31, 2012 and 2013 is not expected to be deductible for tax purposes.

During the fourth quarter of 2013, ETP performed a goodwill impairment test on its Trunkline LNG reporting unit. In accordance with GAAP, ETP performed step one of the goodwill impairment test and determined that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount, primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount. ETP 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, ETP 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, ETP used current replacement costs adjusted for assumed depreciation. ETP also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. ETP 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, ETP 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 consolidated balance sheets 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, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 2,135	$ (264)	$ 2,032	$ (150)
Trade names (20 years)	66	(12)	66	(8)
Patents (9 years)	48	(6)	48	(1)
Other (10 to 15 years)	7	(4)	4	(1)
Total amortizable intangible assets	2,256	(286)	2,150	(160)
Non-amortizable intangible assets:				
Trademarks	294	—	301	—
Total intangible assets	$ 2,550	$ (286)	$ 2,451	$ (160)

Aggregate amortization expense of intangibles assets was as follows:

	Years Ended December 31,		
	2013	2012	2011
Reported in depreciation and amortization	$ 120	$ 70	$ 55

Estimated aggregate amortization expense of intangible assets for the next five years was as follows:

Years Ending December 31:	
2014	$ 123
2015	123
2016	123
2017	123
2018	122

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,	
	2013	2012
Unamortized financing costs (3 to 30 years)	$ 167	$ 152
Regulatory assets	86	93
Deferred charges	144	140
Restricted funds	378	—
Other	147	148
Total other non-current assets, net	$ 922	$ 533

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

Asset Retirement Obligation

We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

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

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

Sunoco Logistics believes it may have additional asset retirement obligations related to its pipeline assets and storage tanks, for which it is not possible to estimate whether or when the retirement obligations will be settled. Consequently, these retirement obligations cannot be measured at this time.

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

	December 31,	
	2013	2012
Southern Union	$ 55	$ 46
Sunoco	84	53
Sunoco Logistics	41	41
	$ 180	$ 140

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 has in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

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

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2013	2012
Interest payable	$ 357	$ 334
Customer advances and deposits	142	61
Accrued capital expenditures	260	427
Accrued wages and benefits	173	250
Taxes payable other than income taxes	211	208
Income taxes payable	4	41
Deferred income taxes	119	130
Other	412	303
Total accrued and other current liabilities	$ 1,678	$ 1,754

Deposits or advances are received from 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 long-term loans with similar terms and average maturities, the aggregate fair value of our consolidated debt obligations as of December 31, 2013 and 2012 was $23.97 billion and $24.15 billion, respectively. As of December 31, 2013 and 2012, the aggregate carrying amount of our consolidated debt obligations was $23.20 billion and $22.05 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, interest rate derivatives, the Preferred Units, the preferred units of a subsidiary and embedded derivatives in the preferred units of a subsidiary (the “Regency Preferred Units”) 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. Derivatives related to the Regency Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected value, and are considered Level 3. At December 31, 2012, the fair value of the Preferred Units was based predominantly on an income approach model and considered Level 3. The Preferred Units were redeemed on April 1, 2013.

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, 2013 and 2012 based on inputs used to derive their fair values:

	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	—
NGLs — Forwards/Swaps	7	5	2	—
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)	—
NGLs — Forwards/Swaps	(9)	(5)	(4)	—
Power — Forwards	(1)	—	(1)	—
Refined Products — Futures	(5)	(5)	—	—
Total commodity derivatives	(233)	(215)	(18)	—
Total liabilities	$ (347)	$ (215)	$ (113)	$ (19)

	Fair Value Measurements at December 31, 2012			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$ 55	$ —	$ 55	$ —
Commodity derivatives:				
Condensate — Forward Swaps	2	—	2	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	11	11	—	—
Swing Swaps IFERC	3	—	3	—
Fixed Swaps/Futures	98	94	4	—
Options — Calls	3	—	3	—
Options — Puts	1	—	1	—
Forward Physical Contracts	1	—	1	—
NGLs — Swaps	2	1	1	—
Power:				
Forwards	27	—	27	—
Futures	1	1	—	—
Options — Calls	2	—	2	—
Refined Products – Futures	5	1	4	—
Total commodity derivatives	156	108	48	—
Total assets	$ 211	$ 108	$ 103	$ —
Liabilities:				
Interest rate derivatives	$ (235)	$ —	$ (235)	$ —
Preferred Units	(331)	—	—	(331)
Embedded derivatives in the Regency Preferred Units	(25)	—	—	(25)
Commodity derivatives:				
Natural Gas:				

Basis Swaps IFERC/NYMEX	(18)	(18)	—	—
Swing Swaps IFERC	(2)	—	(2)	—
Fixed Swaps/Futures	(103)	(94)	(9)	—
Options — Calls	(3)	—	(3)	—
Options — Puts	(1)	—	(1)	—
NGLs — Swaps	(4)	(3)	(1)	—
Power:				
Forwards	(27)	—	(27)	—
Futures	(2)	(2)	—	—
Refined Products – Futures	(8)	(1)	(7)	—
Total commodity derivatives	(168)	(118)	(50)	—
Total liabilities	$ (759)	$ (118)	$ (285)	$ (356)

At December 31, 2013, the fair value of ETP's Trunkline 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. ETP used the income approach to measure the fair value of the Trunkline LNG reporting unit. Under the income approach, ETP 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.

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, 2013
Embedded derivatives in the Regency Preferred Units	Credit Spread	4.16%
	Volatility	23.71%

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, 2013. There were no transfers between the fair value hierarchy levels during the years ended December 31, 2013 or 2012.

Balance, December 31, 2012	$ (356)
Realized loss included in other income (expense)	(9)
Redemption of Preferred Units	340
Net unrealized gains included in other income (expense)	6
Balance, December 31, 2013	$ (19)

Contributions in Aid of Construction Cost

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

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and are as follows:

	Years Ended December 31,		
	2013	2012	2011
Shipping and handling costs – recorded in operating expenses	$ 28	$ 25	$ 40

Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of 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 governmental authorities on a net basis except for our retail marketing operations 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 ETP's retail marketing operations were $2.22 billion and $573 million for the years ended December 31, 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 ETP's or Regency's issuance of respective ETP or Regency 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

ETE 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 state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under our Third 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, we would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2013, 2012 and 2011, 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. Holdco, which owns Sunoco and Southern Union, is a corporate subsidiary. 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 the consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

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

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

We previously have managed 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.

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 entities.

Allocation of Income

For purposes of maintaining partner capital accounts, our Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests.

3. ACQUISITIONS AND RELATED TRANSACTIONS:

2014 Transactions

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the “Panhandle Merger”), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union’s obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million Regency Common Units and 6.3 million Regency Class F Units), and ETP (2.2 million ETP Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings’ guarantee of $600 million of Regency senior notes.

Trunkline LNG Transaction

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

In connection with ETE’s acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG’s regasification facility and the development of a liquefaction project at Trunkline LNG’s facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions, as discussed further in Note 8.

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

In October 2013, Regency announced that it entered into a merger agreement with PVR (“PVR Acquisition”), pursuant to which, Regency intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time approximately $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units (“PVR Unit(s)”) will receive 1.02 Regency Common Units in exchange for each PVR Unit held on the applicable record date. In November 2013, Regency received clearance of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR’s unitholders and other customary closing conditions, and is expected to close in late March 2014. The PVR Acquisition is expected to enhance 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’s Pending Acquisition of Eagle Rock Energy Partners, L.P.’s Midstream Business

On December 23, 2013, Regency announced plans to purchase Eagle Rock Energy Partners, L.P.’s midstream business. This acquisition, valued at approximately $1.3 billion, will complement Regency’s core gathering and processing business, and when combined with the proposed acquisition of PVR Resources, will further diversify Regency’s basin exposure in the Texas Panhandle, East Texas and South Texas. The Partnership has agreed to purchase approximately 16.5 million Regency Common Units for approximately $400 million upon the closing of this acquisition. The Eagle Rock Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock’s unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Regency’s Acquisition of Hoover Energy

On February 3, 2014, Regency completed its previously announced acquisition of the midstream assets of Hoover Energy. The consideration paid by Regency in exchange for the acquired Hoover entities was valued at $282 million (subject to customary post-closing adjustments) and consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy and (ii) $184 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. Regency financed the cash portion of the purchase price through borrowings under its revolving credit facility.

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 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 assets and liabilities of the LDC Disposal Group were classified as assets and liabilities held for sale at December 31, 2012.

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 loss of discontinued operations, excluding effect of taxes and overhead allocations	65	43

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings, a wholly-owned subsidiary of Southern Union, provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis.

ETP's Acquisition of ETE's Holdco Interest

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

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 until our contribution to Holdco discussed below.

Under the terms of the merger agreement, Southern Union stockholders received a total of approximately 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, ETP completed its 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 ETP's equity method investment in Citrus.

Sunoco Merger

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

Sunoco 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 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's interests in Sunoco Logistics were transferred to ETP.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco 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 also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook facility 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 retained an approximately 33% non-operating noncontrolling interest. The fair value of Sunoco'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 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 will provide 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 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's revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco'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.

Holdco Transaction

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

Under the terms of the 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.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Southern Union Merger and 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. Our consolidated balance sheet presented as of December 31, 2012 reflects the purchase price allocations. Certain amounts included in the purchase price allocation as of December 31, 2012 for Southern Union have been changed from amounts reflected as of March 31, 2012 based on management's review of the valuation.

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

	Sunoco [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.

As a result of the Southern Union Merger, we recognized $38 million of merger-related costs during the year ended December 31, 2012. 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, ETP contributed its propane operations, consisting of HOLP and Titan to AmeriGas. ETP received approximately $1.46 billion in cash and approximately 30 million AmeriGas common units. AmeriGas assumed approximately $71 million of existing HOLP debt. In connection with the closing of this transaction, ETP entered into a support agreement with AmeriGas pursuant to which ETP is 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.

We have not reflected the Propane Business as discontinued operations as ETP has a continuing involvement in this business as a result of the investment in AmeriGas that was transferred to ETP as consideration for the transaction.

In June 2012, ETP sold the remainder of its retail propane operations, consisting of its 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 ETP received net proceeds of approximately $43 million.

Sale of Canyon

In October 2012, ETP 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 adjusted 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 Investment in ETP segment.

2011 Transaction

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC ("ETP-Regency LLC"), a joint venture owned 70% by ETP and 30% by Regency, acquired all of the membership interest in LDH, from Louis Dreyfus Highbridge Energy LLC for approximately $1.98 billion in cash (the "LDH Acquisition"), including working capital adjustments. ETP contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price, while Regency contributed approximately $593 million to fund its 30% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

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

ETP accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star's results of operations are consolidated into ETP's NGL transportation and services operations, while Lone Star's results are recorded as an equity method investment in our Investment in Regency segment. Regency's equity method investment in Lone Star is reflected by ETP as noncontrolling interest attributable to Lone Star. These amounts have been eliminated in our consolidated financial statements.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended December 31, 2012 and 2011 are presented as if the Sunoco Merger, Holdco Transaction and LDH Acquisition had been completed on January 1, 2011.

	Years Ended December 31,	
	2012	2011
Revenues	$ 40,398	$ 37,560
Net income	868	865
Net income attributable to partners	866	863
Basic net income per Limited Partner unit	$ 1.55	$ 1.54
Diluted net income per Limited Partner unit	$ 1.55	$ 1.54

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star beginning January 1, 2010 and Southern Union and Sunoco beginning January 1, 2011;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting; and
- include incremental interest expense related to the financing of ETP's proportionate share of the purchase price.

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. <u>ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES</u>:

AmeriGas Partners, L.P.

As discussed in Note 3, on January 12, 2012, ETP received approximately 29.6 million AmeriGas common units in connection with the contribution of its propane operations. On July 12, 2013, ETP sold 7.5 million AmeriGas common units for net proceeds of $346 million, and as of December 31, 2013, ETP owned 22.1 million AmeriGas common units representing an approximate 24% limited partner interest.

The carrying amount of ETP's investment in AmeriGas was $746 million and $1.02 billion as of December 31, 2013 and 2012, respectively, and was reflected in ETP's all other operations. As of December 31, 2013, ETP's investment in AmeriGas reflected $439 million in excess of its proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $184 million is being amortized over a weighted average period of 14 years, and $255 million is being treated as equity method goodwill and non-amortizable intangible assets.

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

Citrus Corp.

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.

ETP recorded its investment in Citrus at $2.0 billion, which exceeded its 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 ETP's investment in Citrus was $1.89 billion and $1.98 billion at December 31, 2013 and 2012, respectively, and was reflected in ETP's interstate transportation and storage operations.

FEP

ETP has a 50% interest in FEP, a 50/50 joint venture with Kinder Morgan Energy Partners LP. 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 ETP's investment in FEP was $144 million and $159 million as of December 31, 2013 and 2012, respectively, and was reflected in ETP's interstate transportation and storage operations.

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 $548 million and $581 million as of December 31, 2013 and 2012, respectively, and was reflected in Regency's natural gas transportation operations.

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 $442 million and $650 million as of December 31, 2013 and 2012, respectively, and was reflected in Regency's natural gas transportation operations.

Summarized Financial Information

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

	December 31,	
	2013	2012
Current assets	$ 1,028	$ 945
Property, plant and equipment, net	10,778	10,979
Other assets	2,664	2,677
Total assets	$ 14,470	$ 14,601
Current liabilities	$ 1,039	$ 1,662
Non-current liabilities	8,139	7,024
Equity	5,292	5,915
Total liabilities and equity	$ 14,470	$ 14,601

	Years Ended December 31,		
	2013	2012	2011
Revenue	$ 4,695	$ 4,492	$ 3,784
Operating income	1,197	863	928
Net income	699	491	536

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

5. NET INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding. Diluted net income per limited partner unit is computed by dividing net income (as adjusted as discussed herein), after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding and the assumed conversion of our Preferred Units, see Note 7. For the diluted earnings per share computation, income allocable to the limited partners is reduced, where applicable, for the decrease in earnings from ETE's limited partner unit ownership in ETP or Regency that would have resulted assuming the incremental units related to ETP's or Regency's equity incentive plans, as applicable, had been issued during the respective periods. Such units have been determined based on the treasury stock method.

The calculation below for the years ended December 31, 2012 and 2011 for diluted net income per limited partner unit excludes the impact of any ETE Common Units that would be issued upon conversion of the Preferred Units, because inclusion would have been antidilutive. The Preferred Units were redeemed April 1, 2013 as discussed in Note 7.

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

	Years Ended December 31,		
	2013	2012	2011
Income from continuing operations	$ 282	$ 1,383	$ 531
Less: Income from continuing operations attributable to noncontrolling interest	99	1,070	221
Income from continuing operations, net of noncontrolling interest	183	313	310
Less: General Partner's interest in income from continuing operations	—	1	1
Income from continuing operations available to Limited Partners	$ 183	$ 312	$ 309
Basic Income from Continuing Operations per Limited Partner Unit:			
Weighted average limited partner units	560.9	533.4	445.9
Basic income from continuing operations per Limited Partner unit	$ 0.33	$ 0.59	$ 0.69
Basic income (loss) from discontinued operations per Limited Partner unit	$ 0.02	$ (0.02)	$ —
Diluted Income from Continuing Operations per Limited Partner Unit:			
Income from continuing operations available to Limited Partners	$ 183	$ 312	$ 309
Dilutive effect of equity-based compensation of subsidiaries	—	(1)	(1)
Diluted income from continuing operations available to Limited Partners	183	311	308
Weighted average limited partner units	560.9	533.4	445.9
Dilutive effect of unconverted unit awards	—	—	—

Weighted average limited partner units, assuming dilutive effect of unvested unit awards	560.9	533.4	445.9
Diluted income from continuing operations per Limited Partner unit	$ 0.33	$ 0.59	$ 0.69
Diluted income (loss) from discontinued operations per Limited Partner unit	$ 0.02	$ (0.02)	$ —

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2013	2012
Parent Company Indebtedness:		
7.50% Senior Notes, due October 15, 2020	$ 1,187	$ 1,800
5.875% Senior Notes, due January 15, 2024	450	—
ETE Senior Secured Term Loan, due March 26, 2017	—	2,000
ETE Senior Secured Term Loan, due December 2, 2018	171	—
ETE Senior Secured Term Loan, due December 2, 2019	1,000	—
ETE Senior Secured Revolving Credit Facility	—	60
Unamortized premiums, discounts and fair value adjustments, net	(7)	(34)
	2,801	3,826
Subsidiary Indebtedness:		
ETP Debt		
6.0% Senior Notes due July 1, 2013	—	350
8.5% Senior Notes due April 15, 2014	292	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	—
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	—
4.9% Senior Notes due February 1, 2024	350	—
7.6% Senior Notes due February 1, 2024	277	—
8.25% Senior Notes due November 15, 2029	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
6.5% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	—
5.95% Senior Notes due October 1, 2043	450	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	—
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Unamortized premiums, discounts and fair value adjustments, net	(34)	(14)
	11,213	9,073
Panhandle Debt		
6.05% Senior Notes due August 15, 2013	—	250
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
7.00% Senior Notes due July 15, 2029	66	66
Term Loan due February 23, 2015	—	455
Unamortized premiums, discounts and fair value adjustments, net	107	136
	1,023	1,757
Regency Debt		
9.375% Senior Notes due June 1, 2016	—	162
6.875% Senior Notes due December 1, 2018	600	600
5.75% Senior Notes due September 1, 2020	400	—
6.5% Senior Notes due July 15, 2021	500	500
5.5% Senior Notes due April 15, 2023	700	700
4.5% Senior Notes due November 1, 2023	600	—

Regency $1.2 billion Revolving Credit Facility due May 21, 2018	510	192
Unamortized premiums, discounts and fair value adjustments, net	—	3
	3,310	2,157
Southern Union Debt[1]		
7.60% Senior Notes due February 1, 2024	82	360
8.25% Senior Notes due November 14, 2029	33	300
Floating Rate Junior Subordinated Notes due November 1, 2066	54	600
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Unamortized premiums, discounts and fair value adjustments, net	48	49
	217	1,519
Sunoco Debt		
4.875% Senior Notes due October 15, 2014	250	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	70	104
	1,035	1,069
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014[2]	175	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	—
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	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Unamortized premiums, discounts and fair value adjustments, net	118	143
	2,503	1,732
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	88	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)
	869	869
Other	228	51
	23,199	22,053
Less: current maturities	637	613
	$ 22,562	$ 21,440

(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.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $301 million in unamortized premiums and fair value adjustments, net:

2014	$ 812
2015	1,047
2016	375
2017	1,220
2018	1,976
Thereafter	17,468
Total	$ 22,898

Long-term debt reflected on our consolidated balance sheets includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap.

Notes and Debentures

ETE Senior Notes

On December 2, 2013, the Parent Company completed a public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024. The Parent Company used net proceeds from this offering, together with a portion of the net proceeds from the Revolver Credit Agreement and the ETE Term Loan Facility, discussed below, to fund the Parent Company's tender offer for a portion of its 7.500% Senior Notes due 2020 (together with the 5.875% Senior Notes due 2024, the "ETE Senior Notes").

The ETE Senior Notes are the Parent Company's senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of its future subordinated debt. The Parent Company's obligations under the ETE Senior Notes are secured on a first-priority basis with its obligations under the Revolver Credit Agreement and the ETE Term Loan Facility, by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Senior Notes are not guaranteed by any of the Parent Company's subsidiaries.

The covenants related to the ETE Senior Notes include a limitation on liens, a limitation on transactions with affiliates, a restriction on sale-leaseback transactions and limitations on mergers and sales of all or substantially all of the Parent Company's assets.

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, ETP became a co-obligor on approximately of $965 million aggregate principal amount of Sunoco's existing senior notes and debentures.

Southern Union Junior Subordinated Notes

The interest rate on the remaining portion of Southern Union's $600 million 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 $600 million at an effective interest rate of 3.32% at December 31, 2013.

ETP Senior Notes

The ETP Senior Notes are unsecured obligations of ETP and the obligation of ETP to repay the ETP Senior Notes is not guaranteed by us or any of ETP's subsidiaries. The ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of ETP's existing and future subsidiaries. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

In January 2013, ETP completed a public offering of $800 million aggregate principal amount of our 3.6% Senior Notes due February 1, 2023 and $450 million aggregate principal amount of its 5.15% Senior Notes due February 1, 2043. ETP used the net proceeds of $1.24 billion from this offering to repay borrowings outstanding under its revolving credit facility and for general partnership purposes.

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

Note Exchange

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

Sunoco Logistics Senior Notes

In January 2013, Sunoco Logistics issued $350 million aggregate principal amount of 3.45% Senior Notes due January 2023 and $350 million aggregate principal amount of 4.95% Senior Notes due January 2043. The net proceeds of $691 million from the offering were used to pay outstanding borrowings under the Sunoco Logistics' Credit Facilities 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 payable semi-annually.

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.

Term Loans and Credit Facilities

ETE Term Loan Facility

On December 2, 2013, the Parent Company entered into a Senior Secured Term Loan Agreement (the "ETE Term Credit Agreement"), which has a scheduled maturity date of December 2, 2019, with an option to extend the term subject to the terms and conditions set forth therein. Pursuant to the ETE Term Credit Agreement, the lenders have provided senior secured financing in an aggregate principal amount of $1.0 billion (the "ETE Term Loan Facility"). The Parent Company shall not be required to make any amortization payments with respect to the term loans under the Term Credit Agreement. Under certain circumstances, the Partnership is required to repay the term loan in connection with dispositions of (a) incentive distribution rights in ETP or Regency, (b) general partnership interests in Regency or (c) equity interests of any Person which owns, directly or indirectly, incentive distribution rights in ETP or Regency or general partnership interests in Regency, in each case, yielding net proceeds in excess of $50 million.

Under the Term Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Term Loan Facility initially is not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The applicable margin for LIBOR rate loans is 2.50% and the applicable margin for base rate loans is 1.50%. Proceeds of the borrowings under the Term Credit Agreement were used to partially fund a tender offer for ETE Senior Notes completed in December 2013, to repay amounts outstanding under the Parent Company's existing term loan credit facility, and to pay transaction fees and expenses related to the tender offer, the ETE Term Loan Facility and other transactions incidental thereto.

ETE Revolving Credit Facility

On December 2, 2013, the Parent Company entered into a credit agreement (the "Revolving Credit Agreement"), which has a scheduled maturity date of December 2, 2018, with an option for the Partnership to extend the term subject to the terms and conditions set forth therein.

Pursuant to the Revolver Credit Agreement, the lenders have committed to provide advances up to an aggregate principal amount of $600 million at any one time outstanding (the "ETE Revolving Credit Facility"), and the Parent Company has the option to request increases in the aggregate commitments provided that the aggregate commitments never exceed $1.0 billion. In February 2014, the Partnership increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

As part of the aggregate commitments under the facility, the Revolver Credit Agreement provides for letters of credit to be issued at the request of the Parent Company in an aggregate amount not to exceed a $150 million sublimit.

Under the Revolver Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets. Borrowings under the Revolver Credit Agreement are not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The issuing fees for all letters of credit are also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the then applicable leverage ratio of the Parent Company. The applicable margin for LIBOR rate loans and letter of credit fees ranges from 1.75% to 2.50% and the applicable margin for base rate loans ranges from 0.75% to 1.50%. The Parent Company will also pay a fee based on its leverage ratio on the actual daily unused amount of the aggregate commitments.

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of ETP'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 ETP's other current and future unsecured debt. ETP uses the ETP Credit Facility to provide temporary financing for the Partnership's growth projects, as well as for general partnership purposes.

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

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

Regency Credit Facility

In May 2013, Regency entered into an amendment to the Regency Credit Facility to increase the borrowing capacity of the Regency Credit Facility to $1.20 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. Indebtedness under the Regency Credit Facility is secured by all of Regency's and certain of its subsidiaries' tangible and intangible assets and guaranteed by certain of Regency's subsidiaries.

In February 2014, Regency entered into the First Amendment to Sixth Amended and Restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million.

As of December 31, 2013, Regency had a balance of $510 million outstanding under the Regency Credit Facility in revolving credit loans and approximately $14 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2013, which is reduced by any letters of credit, was approximately $676 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 2.17%.

The outstanding balance of revolving loans under the Regency Credit Facility bears interest at LIBOR plus a margin or an alternate base rate. The alternate base rate used to calculate interest on base rate loans will be calculated using the greater of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.0%. The applicable margin ranges from 0.63% to 1.5% for base rate loans and 1.63% to 2.5% for Eurodollar loans.

Regency pays (i) a commitment fee ranging between 0.3% 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 1.63% and 2.5% 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 0.2% per annum of the average daily amount of its letter of credit exposure. In December 2011, Regency amended its credit facility to allow for additional investments in its joint ventures.

Panhandle Term Loans

A portion of the proceeds from ETP's September 2013 Senior Notes offering, as discussed below, were used to repay $455 million of borrowings under the LNG Holdings' term loan due February 2015.

Bridge Term Loan Facility

Upon obtaining permanent financing for the Southern Union Merger in March 2012, we terminated a 364-day Bridge Term Loan Facility. For the year ended December 31, 2012, bridge loan related fees reflects the recognition of $62 million of commitment fees upon termination of the facility.

Southern Union Credit Facility

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

Sunoco Logistics Credit Facilities

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

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

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

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The ETE Term Loan Facility and ETE Revolving Credit Facility contain customary representations, warranties, covenants and events of default, including a change of control event of default and limitations on incurrence of liens, new lines of business, merger, transactions with affiliates and restrictive agreements.

The ETE Term Loan Facility and ETE Revolving Credit Facility contain financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to EBITDA (as defined in the agreements) of the Parent Company of not more than 6.0 to 1, with a permitted increase to 7 to 1 during a specified acquisition period following the close of a specified acquisition; and
- EBITDA to interest expense of not less than 1.5 to 1.

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 ETP's and certain of the ETP'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 ETP 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 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.

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 many of the foregoing covenants. The Regency Credit Facility contains 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 contains 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.

Covenants Related to Southern Union

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

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

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

Covenants Related to Sunoco Logistics

Sunoco Logistics' $1.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

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

Compliance With Our Covenants

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

We and our subsidiaries are required to assess compliance quarterly and were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2013.

7. REDEEMABLE PREFERRED UNITS:

ETE Preferred Units

In connection with ETE's acquisition of Regency's general partner in 2010, ETE issued 3,000,000 Preferred Units having an aggregate liquidation preference of $300 million, which were reflected as long-term liabilities in our consolidated balance sheet as of December 31, 2012. The Preferred Units were issued in a private placement at a stated price of $100 per unit and were entitled to a preferential quarterly cash distribution of $2.00 per Preferred Unit.

On April 1, 2013, ETE paid $300 million to redeem (the "Redemption") all of its 3,000,000 outstanding Preferred Units. Prior to the Redemption, on March 28, 2013, ETE paid the holder of the Preferred Units $40 million in cash in exchange for the holder relinquishing its right to receive any premium in connection with a future redemption or conversion of the Preferred Units.

Prior to the April 1, 2013 Redemption, we recorded non-cash charges of approximately $9 million to increase the carrying value of the Preferred Units to the estimated fair value. During 2012, we recorded non-cash charges of approximately $8 million to increase the carrying value of the Preferred Units to the estimated fair value of $331 million as of December 31, 2012.

Preferred Units of Subsidiary

Holders may elect to convert Regency Preferred Units to Regency Common Units at any time. In July 2013, certain holders of the Regency Preferred Units exercised their right to convert an aggregate 2,459,017 Series A Preferred Units into Regency Common Units. Concurrent with this transaction, a gain of $26 million was recognized in other income, net, related to the embedded derivative and reclassified $41 million from the Regency Preferred Units into Regency Common Units. As of December 31, 2013, the remaining Regency Preferred Units were convertible into 2,050,854 Regency Common Units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Regency Preferred Units received fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of Regency's common unit distributions. Holders can elect to convert Regency Preferred Units into Regency Common Units into common units at any time in accordance with the partnership agreement.

The following table provides a reconciliation of the beginning and ending balances of the Regency Preferred Units:

	Regency Preferred Units	Amount
Balance at January 1, 2012	4.4	$ 71
Accretion to redemption value	N/A	2
Balance, December 31, 2012	4.4	$ 73
Regency Preferred Units converted into Regency Common Units	(2.5)	(41)
Balance, December 31, 2013	1.9	$ 32 (1)

(1) This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

8. EQUITY:

Limited Partner Units

Limited partner interests in the Partnership are represented by Common Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Partnership's 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 the Partnership's 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 "Parent Company Quarterly Distributions of Available Cash."

As of December 31, 2013, there were issued and outstanding 559.9 million Common Units representing an aggregate 99.48% limited partner interest in the Partnership.

Our Partnership Agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. For any fiscal year that the Partnership has net profits, such net profits are first allocated to the General Partner until the aggregate amount of net profits for the current and all prior fiscal years equals the aggregate amount of net losses allocated to the General Partner for the current and all prior fiscal years. Second, such net profits shall be allocated to the Limited Partners pro rata in accordance with their respective sharing ratios. For any fiscal year in which the Partnership has net losses, such net losses shall be first allocated to the Limited Partners in proportion to their respective adjusted capital account balances, as defined by the Partnership Agreement, (before taking into account such net losses) until their adjusted capital account balances have been reduced to zero. Second, all remaining net losses shall be allocated to the General Partner. The General Partner may distribute to the Limited Partners funds of the Partnership that the General Partner reasonably determines are not needed for the payment of existing or foreseeable Partnership obligations and expenditures.

Common Units

The change in ETE Common Units during the years ended December 31, 2013, 2012 and 2011was as follows:

	Years Ended December 31,		
	2013	2012	2011
Number of Common Units, beginning of period	559.9	445.9	445.9
Issuance of restricted Common Units under long-term incentive plan	—	—	—

Issuance of common units in connection with Southern Union Merger (See Note 3)	—	114.0	—
Number of Common Units, end of period	559.9	559.9	445.9

Common Unit Split and Repurchase Program

On December 23, 2013, ETE announced that the board of directors of its general partner approved a two-for-one split of the Partnership's outstanding common units (the "Unit Split"). The Unit Split was completed on January 27, 2014. The Unit Split was effected by a distribution of one ETE Common Unit for each common unit outstanding and held by unitholders of record at the close of business on January 13, 2014.

In December 2013, the Partnership announced a common unit repurchase program, whereby the Partnership may repurchase up to $1 billion of ETE Common Units in the open market at the Partnership's discretion, subject to market conditions and other factors, and in accordance with applicable regulatory requirements. The Partnership repurchased 1,695,200 ETE Common Units under this program through February 10, 2014.

Class D Units

On May 1, 2013, Jamie Welch was appointed Group Chief Financial Officer and Head of Corporate Development of LE GP, LLC, the general partner of ETE, effective June 24, 2013. Pursuant to an equity award agreement between Mr. Welch and the Partnership dated April 23, 2013, Mr. Welch received 1,500,000 restricted ETE common units representing limited partner interest. The restricted ETE common units were subject to vesting, based on continued employment with ETE. On December 23, 2013, ETE and Mr. Welch entered into (i) a rescission agreement in order to rescind the original offer letter to the extent it relates to the award of 1,500,000 common units of ETE to Mr. Welch, the original award agreements, and the receipt of cash amounts by Mr. Welch with respect to such awarded units and (ii) a new Class D Unit Agreement between ETE and Mr. Welch providing for the issuance to Mr. Welch of an aggregate of 1,540,000 Class D Units of ETE, which number of Class D Units includes an additional 40,000 Class D Units that were issued to Mr. Welch in connection with other changes to his original offer letter.

Under the terms of the Class D Unit Agreement, 30% of the Class D Units will convert to ETE common units on a one-for-one basis on March 31, 2015, and the remaining 70% will convert to ETE common units on a one-for-one basis on March 31, 2018, subject in each case to (i) Mr. Welch being in Good Standing with ETE (as defined in the Class D Unit Agreement) and (ii) there being a sufficient amount of gain available (based on the ETE partnership agreement) to be allocated to the Class D Units being converted so as to cause the capital account of each such unit to equal the capital account of an ETE Common Unit on the conversion date.

Sale of Common Units by Subsidiaries

The Parent Company accounts for the difference between the carrying amount of its investment in ETP and Regency and the underlying book value arising from issuance of units by ETP or Regency (excluding unit issuances to the Parent Company) as a capital transaction. If ETP or Regency issues units at a price less than the Parent Company's carrying value per unit, the Parent Company assesses whether the investment has been impaired, in which case a provision would be reflected in our statement of operations. The Parent Company did not recognize any impairment related to the issuance of ETP or Regency Common Units during the periods presented.

Sale of Common Units by ETP

The following table summarizes ETP's public offerings of ETP Common Units, all of which have been registered under the Securities Act of 1933 (as amended):

Date	Number of ETP Common Units	Price per ETP Unit	Net Proceeds
April 2011	14.2	$ 50.52	$ 695
November 2011	15.2	44.67	660
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.

ETP's Equity Distribution Program

From time to time, ETP has sold ETP Common Units through an equity distribution agreement. Such sales of ETP 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, ETP entered into equity distribution agreements pursuant to which ETP may sell from time to time ETP Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the year ended December 31, 2013, ETP issued approximately 16.9 million ETP Common Units for $846 million, net of commissions of $9 million. Approximately $145 million of ETP Common Units remained available to be issued under the currently effective equity distribution agreement as of December 31, 2013.

ETP's Equity Incentive Plan Activity

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

ETP's Distribution Reinvestment Program

In April 2011, ETP filed a registration statement with the SEC covering its Distribution Reinvestment Plan (the "DRIP"). The DRIP provides ETP's Unitholders of record and beneficial owners of ETP 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 ETP Common Units. The registration statement covers the issuance of up to 5.8 million ETP Common Units under the DRIP.

During the years ended December 31, 2013, 2012 and 2011, aggregate distributions of approximately $109 million, $43 million and $15 million were reinvested under the DRIP resulting in the issuance in aggregate of approximately 3.7 million ETP Common Units. As of December 31, 2013, a total of 2.1 million ETP Common Units remain available to be issued under the existing registration statement.

ETP Class E Units

There are 8.9 million ETP Class E Units outstanding that are reported by ETP as treasury units. These ETP Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all ETP Unitholders, including the ETP Class E Unitholders, up to $1.41 per unit per year, with any excess thereof available for distribution to ETP Unitholders other than the holders of ETP Class E Units in proportion to their respective interests. The ETP Class E Units are treated by ETP as treasury units for accounting purposes because they are owned by a subsidiary of Holdco, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the ETP Class E Units at a future date.

ETP Class G Units

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

ETP Class H Units

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

The ETP Class H Units are held by a subsidiary of ETE and therefore are reflected by ETP as treasury units in its consolidated financial statements.

Sale of Common Units by Regency

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

Date	Number of Regency Common Units [1]	Price per Regency Unit	Net Proceeds
May 2011	8.5	[1]	$ 204
October 2011	11.5	$ 20.92	232
March 2012	12.7	24.47	297

[1] Regency Units were issued in a private placement.

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.

In June 2012, Regency entered into an Equity Distribution Agreement with Citi 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. Sales of these units, if any, made under the Regency Equity Distribution Agreement will be made by means of ordinary brokers’ transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by Regency and Citi. Under the terms of this agreement, Regency may also sell Regency Common Units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of Regency Common Units to Citi as principal would be pursuant to the terms of a separate agreement between Regency and Citi. Regency intends to use the net proceeds from the sale of these units for general partnership purposes. As of December 31, 2013, Regency received net proceeds of $149 million from Regency Common Units issued pursuant to this Equity Distribution Agreement.

Contributions to Subsidiaries

The Parent Company indirectly owns the entire general partner interest in ETP through its ownership of ETP GP, the general partner of ETP. ETP GP has the right, but not the obligation, to contribute a proportionate amount of capital to ETP to maintain its current general partner interest. ETP GP’s interest in ETP’s distributions is reduced if ETP issues additional units and ETP GP does not contribute a proportionate amount of capital to ETP to maintain its General Partner interest.

The Parent Company owns the entire general partner interest in Regency through its ownership of Regency GP. Regency GP has the right, but not the obligation, to contribute a proportionate amount of capital to Regency to maintain its current general partner interest. Regency GP's interest in Regency's distributions is reduced if Regency issues additional units and Regency GP does not contribute a proportionate amount of capital to Regency to maintain its General Partner interest.

Parent Company Quarterly Distributions of Available Cash

Our distribution policy is consistent with the terms of our Partnership Agreement, which requires that we distribute all of our available cash quarterly. The Parent Company's only cash-generating assets currently consist of distributions from ETP and Regency related to limited and general partner interests, including IDRs. As of December 31, 2013, we had no independent operations outside of our direct and indirect interests in ETP and Regency.

Our distributions declared during the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate	
December 31, 2010	February 7, 2011	February 18, 2011	$	0.27000
March 31, 2011	May 6, 2011	May 19, 2011		0.28000
June 30, 2011	August 5, 2011	August 19, 2011		0.31250
September 30, 2011	November 4, 2011	November 18, 2011		0.31250
December 31, 2011	February 7, 2012	February 17, 2012		0.31250
March 31, 2012	May 4, 2012	May 18, 2012		0.31250
June 30, 2012	August 6, 2012	August 17, 2012		0.31250
September 30, 2012	November 6, 2012	November 16, 2012		0.31250
December 31, 2012	February 7, 2013	February 19, 2013		0.31750
March 31, 2013	May 6, 2013	May 17, 2013		0.32250
June 30, 2013	August 5, 2013	August 19, 2013		0.32750
September 30, 2013	November 4, 2013	November 19, 2013		0.33625
December 31, 2013	February 7, 2014	February 19, 2014		0.34625

ETP's Quarterly Distribution of Available Cash

ETP's Partnership Agreement requires that ETP distribute all of its Available Cash to its Unitholders and its General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any fiscal quarter of ETP, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by its General Partner in its sole discretion to provide for the proper conduct of ETP's 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 ETP's Partnership Agreement.

ETP's distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per ETP Common Unit	
December 31, 2010	February 7, 2011	February 14, 2011	$	0.89375
March 31, 2011	May 6, 2011	May 16, 2011		0.89375
June 30, 2011	August 5, 2011	August 15, 2011		0.89375
September 30, 2011	November 4, 2011	November 14, 2011		0.89375
December 31, 2011	February 7, 2012	February 14, 2012		0.89375
March 31, 2012	May 4, 2012	May 15, 2012		0.89375
June 30, 2012	August 6, 2012	August 14, 2012		0.89375
September 30, 2012	November 6, 2012	November 14, 2012		0.89375
December 31, 2012	February 7, 2013	February 14, 2013		0.89375
March 31, 2013	May 6, 2013	May 15, 2013		0.89375
June 30, 2013	August 5, 2013	August 14, 2013		0.89375
September 30, 2013	November 4, 2013	November 14, 2013		0.90500
December 31, 2013	February 7, 2014	February 14, 2014		0.92000

Following are ETP incentive distributions ETE has agreed to relinquish:

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

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

In addition to the amounts above, in connection with the transfer of Trunkline LNG in February 2014, ETE agreed to relinquish incentive distributions of $50 million, $50 million, $45 million, and $35 million during the years ended December 31, 2016, 2017, 2018 and 2019, respectively.

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

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$ 26.50	$ 26.50	$ 26.50	$ 26.50	$ 106.00
2015	12.50	12.50	13.00	13.00	51.00
2016	18.00	18.00	18.00	18.00	72.00
2017	12.50	12.50	12.50	12.50	50.00
2018	11.25	11.25	11.25	11.25	45.00
2019	8.75	8.75	8.75	8.75	35.00

Regency's Quarterly Distribution of Available Cash

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 paid by Regency since the date of acquisition are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Regency Common Unit
December 31, 2010	February 7, 2011	February 14, 2011	$ 0.445
March 31, 2011	May 6, 2011	May 13, 2011	0.445
June 30, 2011	August 5, 2011	August 12, 2011	0.450
September 30, 2011	November 7, 2011	November 14, 2011	0.455
December 31, 2011	February 6, 2012	February 13, 2012	0.460
March 31, 2012	May 7, 2012	May 14, 2012	0.460
June 30, 2012	August 6, 2012	August 14, 2012	0.460
September 30, 2012	November 6, 2012	November 14, 2012	0.460
December 31, 2012	February 7, 2013	February 14, 2013	0.460
March 31, 2013	May 6, 2013	May 13, 2013	0.460
June 30, 2013	August 5, 2013	August 14, 2013	0.465
September 30, 2013	November 4, 2013	November 14, 2013	0.470
December 31, 2013	February 7, 2014	February 14, 2014	0.475

In conjunction with Southern Union's contributions of SUGS to Regency, ETE agreed to relinquish incentive distributions on the 31.4 million Regency Common Units issued for twenty-four months subsequent to the transaction closing.

Sunoco Logistics Quarterly Distributions of Available Cash

Distributions paid by Sunoco Logistics since the date of acquisition are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Sunoco Logistics Common Unit
December 31, 2012	February 8, 2013	February 14, 2013	$ 0.5450
March 31, 2013	May 9, 2013	May 15, 2013	0.5725
June 30, 2013	August 8, 2013	August 14, 2013	0.6000
September 30, 2013	November 8, 2013	November 14, 2013	0.6300
December 31, 2013	February 10, 2014	February 14, 2014	0.6625

Accumulated Other Comprehensive Income (Loss)

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

	December 31,	
	2013	2012
Net losses on commodity related hedges	$ (4)	$ (3)
Available-for-sale securities	2	—
Foreign currency translation adjustment	(1)	—

Actuarial gain (loss) related to pensions and other postretirement benefits	56	(10)
Equity investments, net	8	(9)
Subtotal	61	(22)
Amounts attributable to noncontrolling interest	(52)	10
Total AOCI included in partners' capital, net of tax	$ 9	$ (12)

The table below sets forth the tax amounts included in the respective components of other comprehensive income (loss):

	December 31,	
	2013	2012
Net gains on commodity related hedges	$ —	$ 2
Actuarial (gain) loss relating to pension and other postretirement benefits	(39)	5
Total	$ (39)	$ 7

9. UNIT-BASED COMPENSATION PLANS:

We, ETP, Sunoco Logistics and Regency have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase Common Units, restricted units, phantom units, distribution equivalent rights ("DERs"), common unit appreciation rights, and other unit-based awards.

ETE Long-Term Incentive Plan

The Board of Directors or the Compensation Committee of the board of directors of the our General Partner (the "Compensation Committee") may from time to time grant additional awards to employees, directors and consultants of ETE's general partner and its affiliates who perform services for ETE. The plan provides for the following types of awards: restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The number of additional units that may be delivered pursuant to these awards is limited to 6,000,000 units. As of December 31, 2013, 5,693,789 units remain available to be awarded under the plan.

In December 2013, 1,540,000 Class D Units were granted to an ETE employee, Jaime Welch. Under the terms of the Class D Unit Agreement, 30% of the Class D Units granted to Welch will convert to ETE common units on a one-for-one basis on March 31, 2015, and the remaining 70% will convert to ETE common units on a one-for-one basis on March 31, 2018, subject in each case to (i) Mr. Welch being in Good Standing with ETE (as defined in the Class D Unit Agreement) and (ii) there being a sufficient amount of gain available (based on the ETE partnership agreement) to be allocated to the Class D Units being converted so as to cause the capital account of each such unit to equal the capital account of an ETE Common Unit on the conversion date. See further discussion at Note 8 to our consolidated financial statements.

During 2013, no awards were granted to ETE employees except the 1,540,000 Class D Units discussed above and 12,084 ETE units were granted to non-employee directors. Under our equity incentive plans, our non-employee directors each receive grants that vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

During 2013, a total of 56,048 ETE Common Units vested, with a total fair value of $2.1 million as of the vesting date. As of December 31, 2013, excluding Class D units, a total of 65,980 restricted units granted to ETE employees and directors remain outstanding, for which we expect to recognize a total of less than $1 million in compensation over a weighted average period of 1.7 years. As of December 31, 2013, a total of 1,540,000 Class D Units granted to Mr. Welch remain outstanding, for which we expect to recognize a total of $37 million in compensation over a weighted average period of 3.5 years.

ETP Unit-Based Compensation Plans

Unit Grants

ETP has 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 ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. We refer to these rights as "distribution equivalent rights." Under ETP's equity incentive plans, ETP's non-employee directors each receive grants with a five-year service vesting requirement.

Award Activity

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

	Number of ETP Units	Weighted Average Grant-Date Fair Value Per ETP Unit
Unvested awards as of December 31, 2012	1.9	$ 46.95
Awards granted	2.1	50.54
Awards vested	(0.6)	45.62
Awards forfeited	(0.2)	45.72
Unvested awards as of December 31, 2013	3.2	49.65

During the years ended December 31, 2013, 2012 and 2011, the weighted average grant-date fair value per unit award granted was $50.54, $43.93 and $48.35, respectively. The total fair value of awards vested was $26 million, $29 million and $27 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2013, a total of 3.2 million unit awards remain unvested, for which ETP expects to recognize a total of $116 million in compensation expense over a weighted average period of 2.1 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 0.6 million Sunoco common units. As of December 31, 2013, a total of 0.6 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $21 million of expense over a weighted-average period of 2.8 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by an ETE officer, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the ETP officers vested in the ETE units at a rate of 20% per year. As these ETE units conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards were paid by ETP or ETE. As these units were outstanding prior to these awards, these awards did not represent an increase in the number of outstanding units of either ETP or ETE and were not dilutive to cash distributions per unit with respect to either ETP or ETE.

ETP recognized non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded to the ETP employees assuming no forfeitures. For the years ended December 31, 2013, 2012 and 2011, ETP recognized non-cash compensation expense, net of forfeitures, of less than $1 million, $1 million and $2 million, respectively, as a result of these awards. As of December 31, 2013, no rights related to ETE common units remain outstanding.

Regency Unit-Based Compensation Plans

Regency has the following awards outstanding as of December 31, 2013:

- 142,550 Regency Common Unit options, all of which are exercisable, with a weighted average exercise price of $22.04 per unit option; and
- 982,242 Regency Phantom Units, with a weighted average grant date fair value of $23.16 per Phantom Unit.

Regency expects to recognize $19 million of compensation expense related to the Regency Phantom Units over a period of 3.3 years.

10. INCOME TAXES:

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

	Years Ended December 31,		
	2013	2012	2011
Current expense (benefit):			
Federal	$ 51	$ (3)	$ (1)
State	(1)	6	17
Total	50	3	16
Deferred expense:			
Federal	(14)	41	—
State	57	10	1
Total	43	51	1
Total income tax expense from continuing operations	$ 93	$ 54	$ 17

Historically, our effective tax 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, Sunoco and Holdco transactions (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, 2013 and 2012 is as follows:

	December 31, 2013			December 31, 2012		
	Corporate Subsidiaries[(1)]	Partnership[(2)]	Consolidated	Corporate Subsidiaries[(1)]	Partnership[(2)]	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$ (172)	$ —	$ (172)	$ (4)	$ —	$ (4)
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	241	—	241	—	—	—
Nondeductible executive compensation	—	—	—	28	—	28
State income taxes (net of federal income tax effects)	31	10	41	9	2	11
Other	(16)	(1)	(17)	19	—	19
Income tax from continuing operations	$ 84	$ 9	$ 93	$ 52	$ 2	$ 54

(1) Includes Holdco, Oasis Pipeline Company, Pueblo, Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. The latter three entities were acquired in the Sunoco Merger. Holdco, which was formed via the Sunoco Merger and the Holdco Transaction (see Note 3), includes Sunoco and Southern Union and their subsidiaries. ETE held a 60% interest in Holdco until April 30, 2013. Subsequent to the Holdco Acquisition (see Note 3) on April 30, 2013, ETP owns 100% of Holdco.

(2) Includes ETE and its respective 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,	
	2013	2012
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 217	$ 270
Pension and other postretirement benefits	57	127
Long term debt	108	117
Other	104	290
Total deferred income tax assets	486	804
Valuation allowance	(74)	(94)
Net deferred income tax assets	412	710
Deferred income tax liabilities:		
Properties, plants and equipment	(1,624)	(2,026)
Inventory	(302)	(516)
Investments in unconsolidated affiliates	(2,245)	(1,543)
Trademarks	(180)	(192)
Other	(45)	(129)
Total deferred income tax liabilities	(4,396)	(4,406)
Net deferred income tax liability	(3,984)	(3,696)
Less: current portion of deferred income tax assets (liabilities)	(119)	(130)
Accumulated deferred income taxes	$ (3,865)	$ (3,566)

The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (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,	
	2013	2012
Net deferred income tax liability, beginning of year	$ (3,696)	$ (214)
Southern Union acquisition	—	(1,428)
Sunoco acquisition	—	(1,989)
SUGS Contribution to Regency	(115)	—
Tax provision (including discontinued operations)	(124)	(62)
Other	(49)	(3)
Net deferred income tax liability	$ (3,984)	$ (3,696)

Holdco and other corporate subsidiaries have gross federal net operating loss carryforwards of $216 million, all of which will expire in 2032. Holdco has $40 million of federal alternative minimum tax credits which do not expire. Holdco and other corporate subsidiaries have state net operating loss carryforward benefits of $101 million, net of federal tax, which expire between 2013 and 2032. The valuation allowance of $74 million is applicable to the state net operating loss carryforward benefits applicable to Sunoco pre-acquisition periods.

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

	Years Ended December 31,		
	2013	2012	2011
Balance at beginning of year	$ 27	$ 2	$ 2
Additions attributable to acquisitions	—	28	—
Additions attributable to tax positions taken in the current year	—	—	1
Additions attributable to tax positions taken in prior years	406	—	—
Settlements	—	—	—
Lapse of statute	(4)	(3)	(1)
Balance at end of year	$ 429	$ 27	$ 2

As of December 31, 2013, we have $425 million ($418 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 $6 million ($5 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco’s 2004 through 2011 open statute years, Sunoco has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco 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 consolidated balance sheet as of December 31, 2013.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2013, we recognized interest and penalties of less than $1 million. At December 31, 2013, we have interest and penalties accrued of $6 million, net of tax.

In general, ETE and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2009, except Sunoco, Regency and Pueblo which are no longer subject to examination by the IRS for tax years prior to 2007 and Southern Union which is no longer subject to examination by the IRS for tax years prior to and 2004.

Sunoco has been examined by the IRS for the 2007 and 2008 tax years, however, the statutes remain open for both of these tax years due to carryback of net operating losses. Sunoco is currently under examination for the years 2009 through 2011, but due to the aforementioned carryback, such years also impact Sunoco’s tax liability for the years 2004 through 2008. With the exception of the claims regarding government incentive payments discussed above, all issues are resolved. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2013, the IRS has proposed only one adjustment for the years under examination. For the 2006 tax year, the IRS is challenging $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of its distribution operations and its gathering and processing operations. We will vigorously defend and believe Southern Union’s tax position will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to this tax position. Regency is also under examination by the IRS for the 2007 and 2008 tax years. The IRS has proposed adjustments in both of these examinations which are under review at the Appeals level. We believe Regency will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to these tax positions. The proposed adjustments with respect to Regency would not have a material impact upon our financial statements.

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

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

FERC Audit

The FERC recently completed an audit of PEPL, a subsidiary of Southern Union, for the period from January 1, 2010 through December 31, 2011, to evaluate its compliance with the Uniform System of Accounts as prescribed by the FERC, annual and quarterly financial reporting to the FERC, reservation charge crediting policy and record retention. An audit report was received in August 2013 noting no issues that would have a material impact on the Partnership’s historical financial position or results of operations.

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

PEPL Holdings Guarantee of Collection

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

NGL Pipeline Regulation

Lone Star has interests in NGL pipelines located in Texas and New Mexico. Lone Star commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the ICA and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. 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.

Commitments

In the normal course of business, ETP and Regency purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on its 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 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $151 million, $60 million and $29 million for the years ended December 31, 2013, 2012 and 2011, respectively, which include contingent rentals totaling $22 million and $6 million in 2013 and 2012, respectively. During the years ended December 31, 2013, and 2012, approximately $24 million and $4 million, respectively, of rental expense was recovered through related sublease rental income.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2014	$	83
2015		81
2016		72
2017		68
2018		55
Thereafter		454
Future minimum lease commitments		813
Less: Sublease rental income		(57)
Net future minimum lease commitments	$	756

ETP and Regency's joint venture agreements require that they fund their proportionate share of capital contributions to their unconsolidated affiliates. Such contributions will depend upon their 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 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.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. Subsequent to the settlement of these cases, the plaintiffs' attorneys sought compensation from Sunoco for attorneys' fees related to their efforts in obtaining these additional disclosures. In January 2013, Sunoco entered into agreements to compensate the plaintiffs' attorneys in the state court actions in the aggregate amount of not more than $950,000 and to compensate the plaintiffs' attorneys in the federal court action in the amount of not more than $250,000. The payment of $950,000 was made in July 2013.

Litigation Relating to the Southern Union Merger

In June 2011, several putative class action lawsuits were filed in the Judicial District Court of Harris County, Texas naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. The lawsuits were styled *Jaroslawicz v. Southern Union Company, et al.*, Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas and *Magda v. Southern Union Company, et al.*, Cause No. 2011-37134, in the 11th Judicial District Court of Harris County, Texas. The lawsuits were consolidated into an action styled *In re: Southern Union Company*; Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas. Plaintiffs allege that the Southern Union directors breached their fiduciary duties to Southern Union's stockholders in connection with the Merger and that Southern Union and ETE aided and abetted the alleged breaches of fiduciary duty. The amended petitions allege that the Merger involves an unfair price and an inadequate sales process, that Southern Union's directors entered into the Merger to benefit themselves personally, including through consulting and noncompete agreements, and that defendants have failed to disclose all material information related to the Merger to Southern Union stockholders. The amended petitions seek injunctive relief, including an injunction of the Merger, and an award of attorneys' and other fees and costs, in addition to other relief. On October 21, 2011, the court denied ETE's October 13, 2011, motion to stay the Texas proceeding in favor of cases pending in the Delaware Court of Chancery.

Also in June 2011, several putative class action lawsuits were filed in the Delaware Court of Chancery naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. Three of the lawsuits also named Merger Sub as a defendant. These lawsuits are styled: *Southeastern Pennsylvania Transportation Authority, et al. v. Southern Union Company, et al.*, C.A. No. 6615-CS; *KBC Asset Management NV v. Southern Union Company, et al.,* C.A. No. 6622-CS; *LBBW Asset Management Investment GmbH v. Southern Union Company, et al.*, C.A. No. 6627-CS; and *Memo v. Southern Union Company, et al.*, C.A. No. 6639-CS. These cases were consolidated with the following style: *In re Southern Union Co. Shareholder Litigation*, C.A. No. 6615-CS, in the Delaware Court of Chancery. The consolidated complaint asserts similar claims and allegations as the Texas state-court consolidated action. On July 25, 2012, the Delaware plaintiffs filed a notice of voluntary dismissal of all claims without prejudice. In the notice, plaintiffs stated their claims were being dismissed to avoid duplicative litigation and indicated their intent to join the Texas case.

On September 18, 2013, the plaintiff dismissed without prejudice its lawsuit against all defendants.

MTBE Litigation

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

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

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

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.

Other Litigation and Contingencies

In November 2011, a derivative lawsuit was filed in the Judicial District Court of Harris County, Texas naming as defendants ETP, ETP GP, ETP LLC, the boards of directors of ETP LLC (collectively with ETP GP and ETP LLC, the "ETP Defendants"), certain members of management for ETP and ETE, ETE, and Southern Union. The lawsuit is styled W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, in the 157th Judicial District Court of Harris County, Texas. Plaintiffs assert claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and the individual defendants. Plaintiffs also assert claims for aiding and abetting and tortious interference with contract against Southern Union. On October 5, 2012, certain defendants filed a motion for summary judgment with respect to the primary allegations in this action. On December 13, 2012, Plaintiffs filed their opposition to the motion for summary judgment. Defendants filed a reply on December 19, 2012. On December 20, 2012, the court conducted an oral hearing on the motion. Plaintiffs filed a post-hearing sur-reply on January 7, 2013. On January 16, 2013, the Court granted defendants' motion for summary judgment. The parties agreed to settle the matter and executed a memorandum of understanding. On October 4, 2013, the Court approved the settlement and ordered the case dismissed with prejudice.

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, 2013 and 2012, accruals of approximately $46 million and $42 million, respectively, were reflected on our balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

No amounts have been recorded in our December 31, 2013 or 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Litigation Related to Incident at JJ's Restaurant. On February 19, 2013, there was a natural gas explosion at JJ's Restaurant located at 910 W. 48th Street in Kansas City, Missouri. Effective September 1, 2013, Laclede Gas Company, a subsidiary of The Laclede Group, Inc. ("Laclede"), assumed any and all liability arising from this incident in ETP's sale of the assets of MGE to Laclede.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The Attorney General 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 Attorney General 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, Southern Union's Vice Chairman, President and COO, 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 Attorney General contends only would 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. Southern Union believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Southern Union 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.
- Southern Union's distribution operations are responsible for soil and groundwater remediation at certain sites related to manufactured gas plants ("MGPs") and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco 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, 2013, Sunoco had been named as a PRP at 40 identified or potentially identifiable as "Superfund" sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco'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. 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,	
	2013	2012
Current	$ 47	$ 46
Non-current	356	166
Total environmental liabilities	$ 403	$ 212

In 2013, 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.

During the years ended December 31, 2013 and 2012, the Partnership recorded $41 million and $12 million, respectively, of expenditures related to environmental cleanup programs.

The EPA's Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

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

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

Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline operations located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of the OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, our subsidiaries 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. Following is a description of price risk management activities by segment.

ETP

ETP injects and holds natural gas in its 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). ETP uses financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, ETP locks 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 ETP designates the related financial contract as a fair value hedge for accounting purposes, ETP values the hedged natural gas inventory at current spot market prices along with the financial derivative ETP uses 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, ETP will record unrealized gains or lower unrealized losses. If the spread widens, ETP will record unrealized losses or lower unrealized gains. Typically, as ETP enters 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.

ETP is also exposed to market risk on natural gas it retains for fees in its intrastate transportation and storage operations and operational gas sales on its interstate transportation and storage operations. ETP uses 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.

ETP is also exposed to commodity price risk on NGLs and residue gas it retains for fees in its midstream operations whereby its 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. ETP uses 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.

ETP may use derivatives in ETP's NGL transportation and services operations to manage ETP's 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.

ETP's trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to its transportation and storage operations and are netted in cost of products sold in the consolidated statements of operations. Additionally, ETP also has trading activities related to power and natural gas in its other operations which are also netted in cost of products sold. As a result of its trading activities and the use of derivative financial instruments in its transportation and storage operations, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. ETP attempts 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 ETP's commodity risk management policy.

Derivatives are utilized in ETP's other operations in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. ETP attempts to maintain balanced positions in its marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist.

The following table details ETP's outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	9,457,500	2014-2019	—	—
Basis Swaps IFERC/NYMEX [1]	(487,500)	2014-2017	(30,980,000)	2013-2014

Swing Swaps	1,937,500	2014-2016	—	—
Power (Megawatt):				
Forwards	351,050	2014	19,650	2013
Futures	(772,476)	2014	(1,509,300)	2013
Options — Puts	(52,800)	2014	—	—
Options — Calls	103,200	2014	1,656,400	2013
Crude (Bbls) – Futures	103,000	2014	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	570,000	2014	150,000	2013
Swing Swaps IFERC	(9,690,000)	2014-2016	(83,292,500)	2013
Fixed Swaps/Futures	(8,195,000)	2014-2015	27,077,500	2013
Forward Physical Contracts	5,668,559	2014-2015	11,689,855	2013-2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	2014	(30,000)	2013
Refined Products (Bbls) – Futures	(1,133,600)	2014	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(7,352,500)	2014	(18,655,000)	2013
Fixed Swaps/Futures	(50,530,000)	2014	(44,272,500)	2013
Hedged Item — Inventory	50,530,000	2014	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,825,000)	2014	—	—
Fixed Swaps/Futures	(12,775,000)	2014	(8,212,500)	2013
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	2014	(930,000)	2013
Refined Products (Bbls) – Futures	—	—	(98,000)	2013
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.

We expect gains of $4 million related to ETP's commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

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, 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.

Regency is exposed to market risks associated with commodity prices, counterparty credit, and interest rates. Regency's management and the board of directors of Regency GP have established comprehensive risk management policies and procedures to monitor and manage these market risks. Regency GP is responsible for delegation of transaction authority levels, and the Risk Management Committee of Regency GP is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Regency GP's Risk Management Committee receives regular briefings on positions and exposures, credit exposures, and overall risk management in the context of market activities.

Regency'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 Regency's call option. These embedded derivatives are accounted for using mark-to-market accounting. Regency does not expect the embedded derivatives to affect its cash flows.

The following table details Regency's outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Non-Trading)				
Natural Gas (MMBtu) — Fixed Swaps/Futures	24,455,000	2014-2015	8,395,000	2013-2014
Propane (Gallons) — Forwards/Swaps	52,122,000	2014-2015	3,318,000	2013
NGLs (Barrels) — Forwards/Swaps	438,000	2014	243,000	2013-2014
WTI Crude Oil (Barrels) — Forwards/Swaps	521,000	2014	356,000	2014

As of December 31, 2013, Regency has less than $1 million in net hedging gains in AOCI, all of which will be amortized to earnings over the next 3 months.

Interest Rate Risk

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

The following is a summary of interest rate swaps outstanding as of December 31, 2013, none of which are designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2013	December 31, 2012
ETE	March 2017	Pay a fixed rate of 1.25% and receive a floating rate	$ —	$ 500
ETP	July 2013[2]	Forward starting to pay a fixed rate of 4.03% and receive a floating rate	—	400
ETP	July 2014[2]	Forward starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union[3]	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union[3]	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

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

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory terminate date the same as the effective date. During the year ended December 31, 2013, ETP settled $400 million of ETP's forward-starting interest rate swaps that had an effective date of July 2013.

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

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 a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure with a single counterparty or affiliated group of counterparties.

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

ETP has 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 its pre-established credit limit with the counterparty. Margin deposits are returned to ETP on the settlement date for non-exchange traded derivatives. ETP exchanges 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.

Regency is exposed to credit risk from its derivative counterparties. Regency does not require collateral from these counterparties as it deals primarily with financial institutions when entering into financial derivatives, and enters into master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If Regency's counterparties failed to perform under existing swap contracts, Regency's maximum loss as of December 31, 2013 would be $4 million, which would be reduced by less than $1 million, due to the netting feature.

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 balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2013 and 2012:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31,	December 31,	December 31,	December 31,

	2013	2012	2013	2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 3	$ 8	$ (18)	$ (10)
	3	8	(18)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 227	$ 110	$ (209)	$ (116)
Commodity derivatives	43	40	(48)	(44)
Current assets held for sale	—	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	—	(9)
Interest rate derivatives	47	55	(95)	(235)
Embedded derivatives in Regency Preferred Units	—	—	(19)	(25)
	317	207	(371)	(429)
Total derivatives	$ 320	$ 215	$ (389)	$ (439)

In addition to the above derivatives, $7 million of option premiums were included in price risk management liabilities as of December 31, 2012.

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, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$ 42	$ 28	$ (38)	$ (27)
Broker cleared derivative contracts	Other current assets (liabilities)	264	149	(318)	(228)
		306	177	(356)	(255)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	2
Counterparty netting	Price risk management assets (liabilities)	(36)	(25)	36	25
Payments on margin deposit	Other current assets	(1)	—	55	59
		(37)	(25)	91	86
Net derivatives with offsetting agreements		269	152	(265)	(169)
Derivatives without offsetting agreements		51	63	(124)	(270)
Total derivatives		$ 320	$ 215	$ (389)	$ (439)

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,		
	2013	2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$ (1)	$ 8	$ 6
Total	$ (1)	$ 8	$ 6

	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,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$ 4	$ 14	$ 19
Total		$ 4	$ 14	$ 19

	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, 2013	2012	2011
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ 8	$ 54	$ 34
Total		$ 8	$ 54	$ 34

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives — Years Ended December 31, 2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives – Trading	Cost of products sold	$ (11)	$ (7)	$ (30)
Commodity derivatives – Non-trading	Cost of products sold	(21)	26	9
Commodity derivatives – Non-trading	Deferred gas purchases	(3)	(26)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	53	(19)	(78)
Embedded derivatives	Other income (expense)	6	14	18
Total		$ 24	$ (12)	$ (81)

13. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all employees, including those of ETP and Regency. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries have made matching contributions of $47 million, $30 million and $17 million to the 401(k) savings plan for the years ended December 31, 2013, 2012 and 2011, respectively.

Pension and Other Postretirement Benefit Plans

Southern Union

Southern Union postretirement benefits expense for the year ended December 31, 2013 reflected the impact of changes Southern Union adopted as of September 30, 2013 to change its retiree medical benefits program effective January 1, 2014 which placed all retirees on a common 75% employer/25% retiree cost sharing platform, subject to caps on annual average per capita expenditures by Southern Union. Postretirement benefits expense for the year ended December 31, 2012 reflects the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. Southern Union previously had postretirement health care and life insurance plans ("other postretirement plans") that covered substantially all employees.

In 2012, Southern Union had funded non-contributory defined benefit pension plans that covered substantially all employees of Southern Union's distribution operations. These operations were sold in 2013, see Note 3. Normal retirement age is 65, but certain plan provisions allowed for earlier retirement. Pension benefits were calculated under formulas principally based on average earnings and length of service for salaried and non-union employees and average earnings and length of service or negotiated non-wage based formulas for union employees.

Sunoco

Sunoco has both funded and unfunded noncontributory defined benefit pension plans. Sunoco also has plans which provide health care benefits for substantially all of its current retirees ("postretirement benefit plans"). The postretirement benefit plans are unfunded and the costs are shared by Sunoco and its retirees. Prior to the Sunoco Merger on October 5, 2012, pension benefits under Sunoco's defined benefit plans were frozen for most of the participants in these plans at which time Sunoco instituted a discretionary profit-sharing contribution on behalf of these employees in its defined contribution plan. Postretirement medical benefits were also phased down or eliminated for all employees retiring after July 1, 2010. Sunoco has established a trust for its postretirement benefit liabilities by making a tax-deductible contribution of approximately $200 million and restructuring the retiree medical plan to eliminate Sunoco's liability beyond this funded amount. The retiree medical plan change eliminated substantially all of Sunoco'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, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Change in benefit obligation:					
Benefit obligation at beginning of period	$ 1,117	$ 78	$ 296	$ 1,257	$ 359
Service cost	3	—	—	3	1
Interest cost	33	2	6	15	3
Amendments	—	—	2	—	17
Benefits paid, net	(99)	(16)	(26)	(71)	(8)
Curtailments	—	—	—	—	(80)
Actuarial (gain) loss and other	(74)	(3)	(14)	(9)	4
Settlements	(95)	—	—	—	—
Dispositions	(253)	—	(41)	—	—
Benefit obligation at end of period	$ 632	$ 61	$ 223	$ 1,195	$ 296
Change in plan assets:					
Fair value of plan assets at beginning of period	906	—	312	941	306
Return on plan assets and other	43	—	17	22	5
Employer contributions	—	—	8	14	9
Benefits paid, net	(99)	—	(26)	(71)	(8)
Settlements	(95)	—	—	—	—
Dispositions	(155)	—	(27)	—	—
Fair value of plan assets at end of period	$ 600	$ —	$ 284	$ 906	$ 312
Amount underfunded (overfunded) at end of period	$ 32	$ 61	$ (61)	$ 289	$ (16)
Amounts recognized in the consolidated balance sheets consist of:					
Non-current assets	$ —	$ —	$ 86	$ —	$ 59
Current liabilities	—	(9)	(2)	(15)	(2)
Non-current liabilities	(32)	(52)	(23)	(274)	(41)
	$ (32)	$ (61)	$ 61	$ (289)	$ 16
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:					
Net actuarial gain	$ (86)	$ (4)	$ (25)	$ (1)	$ (1)
Prior service cost	—	—	18	—	16
	$ (86)	$ (4)	$ (7)	$ (1)	$ 15

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Projected benefit obligation	$ 632	$ 61	N/A	$ 1,195	N/A
Accumulated benefit obligation	632	61	223	1,179	$ 225
Fair value of plan assets	600	—	284	906	185

Components of Net Periodic Benefit Cost

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$ 3	$ —	$ 3	$ 1

Interest cost	35	6	15	3
Expected return on plan assets	(54)	(9)	(21)	(5)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	2	—	—	—
Special termination benefits charge	—	—	2	—
Curtailment recognition [(1)]	—	—	—	(15)
Settlements	(2)	—	—	—
	(16)	(2)	(1)	(16)
Regulatory adjustment [(2)]	5	—	9	2
Net periodic benefit cost	$ (11)	$ (2)	$ 8	$ (14)

(1) Subsequent to the Southern Union Merger, Southern Union amended certain of its other postretirement employee benefit plans, which prospectively restrict participation in the plans for the impacted active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, Southern Union recorded a pre-tax curtailment gain of $75 million. Such gain was offset by establishment of a non-current refund liability in the amount of $60 million. As such, the net curtailment gain recognition was $15 million.

(2) Southern Union has historically recovered certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers in its distribution operation. 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, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65%	2.33%	3.41%	2.39%
Rate of compensation increase	N/A	N/A	3.17%	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, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.50%	2.68%	2.37%	2.43%
Expected return on assets:				
Tax exempt accounts	7.50%	6.95%	7.63%	7.00%
Taxable accounts	N/A	4.42%	N/A	4.50%
Rate of compensation increase	N/A	N/A	3.02%	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 Southern Union's and Sunoco's other postretirement benefit plans are shown in the table below:

	December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.57%	7.78%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.42%	5.32%
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 Southern Union 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 pension plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 70%, fixed income of 15% to 35%, alternative assets of 10% to 35% and cash of 0% to 10%. To achieve diversity within its other postretirement plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of 0% to 10%.

The investment strategy of Sunoco 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, maintain a sufficient funded status of the plans and limit required contributions. Sunoco has targeted the following asset allocations: equity of 35%, fixed income of 55%, and private equity investments of 10%. Sunoco anticipates future shifts in targeted asset allocations from equity securities to fixed income securities if funding levels improve due to asset performance or Sunoco contributions.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	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 66% equities, 10% fixed income securities, and 24% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy: Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 25	$ 25	$ —	$ —
Mutual funds [1]	516	—	433	83
Fixed income securities	354	—	354	—
Multi-strategy hedge funds [2]	11	—	11	—
Total	$ 906	$ 25	$ 798	$ 83

(1) Primarily comprised of approximately 36% equities, 54% fixed income securities, and 10% in other investments as of December 31, 2012.

(2) Primarily includes hedge funds that invest in multiple strategies, including relative value, opportunistic/macro, long/short equities, merger arbitrage/event driven, credit, and short selling strategies, to generate long-term capital appreciation through a portfolio having a diversified risk profile with relatively low volatility and a low correlation with traditional equity and fixed-income markets. These investments can generally be redeemed effective as of the last day of a calendar quarter at the net asset value per share of the investment with approximately 65 days prior written notice.

The fair value of the other postretirement plan assets by asset category at the dates indicated is as follows:

	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.

	Fair Value as of	Fair Value Measurements at December 31, 2012

	December 31, 2012	Using Fair Value Hierarchy Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 7	$ 7	$ —	$ —
Mutual funds [(1)]	147	126	21	—
Fixed income securities	158	—	158	—
Total	$ 312	$ 133	$ 179	$ —

(1) Primarily comprised of approximately 19% equities, 74% fixed income securities, 4% cash, and 3% in other investments as of December 31, 2012.

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 $23 million to pension plans and approximately $18 million to other postretirement plans in 2014. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Southern Union's and Sunoco'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:

Years	Pension Benefits Funded Plans	Pension Benefits Unfunded Plans	Other Postretirement Benefits (Gross, Before Medicare Part D)
2014	$ 82	$ 9	$ 31
2015	77	9	29
2016	67	8	28
2017	61	7	26
2018	56	7	24
2019 – 2023	220	23	87

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.

Southern Union does not expect to receive any Medicare Part D subsidies in any future periods.

14. RELATED PARTY TRANSACTIONS:

The Parent Company has agreements with subsidiaries to provide or receive various general and administrative services. The Parent Company pays ETP to provide services on its behalf and the behalf of other subsidiaries of the Parent Company. The Parent Company receives management fees from certain of its subsidiaries, which include the reimbursement of various general and administrative services for expenses incurred by ETP on behalf of those subsidiaries. All such amounts have been eliminated in our consolidated financial statements.

In the ordinary course of business, our subsidiaries have related party transactions between each other which are generally based on transactions made at market-related rates. Our consolidated revenues and expenses reflect the elimination of all material intercompany transactions (see Note 15).

In addition, subsidiaries of ETE recorded sales with affiliates of $1.44 billion, $189 million and $1.05 billion during the years ended December 31, 2013, 2012 and 2011, respectively.

15. REPORTABLE SEGMENTS:

As a result of the acquisition of Trunkline LNG in February 2014, our reportable segments were re-evaluated and currently reflect the following reportable segments, which conduct their business exclusively in the United States of America, as follows:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Regency, including the consolidated operations of Regency;
- Investment in Trunkline LNG, including the consolidated operations of Trunkline LNG; and
- Corporate and Other, including the following:
    - activities of the Parent Company; and
    - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane

Partners, L.P.

Related party transactions among our segments are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

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 includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

As discussed in Note 3, Regency completed its acquisition of SUGS on April 30, 2013. Therefore, the investment in Regency segment amounts have been retrospectively adjusted to reflect SUGS beginning March 26, 2012.

Eliminations in the tables below include the following:

- ETP's Segment Adjusted EBITDA reflects 100% of Lone Star, which is a consolidated subsidiary of ETP. Regency's Segment Adjusted EBITDA includes its 30% investment in Lone Star. Therefore, 30% of the results of Lone Star are included in eliminations.

- ETP's Segment Adjusted EBITDA reflects the results of SUGS from March 26, 2012 to April 30, 2013. Because the SUGS Contribution was a transaction between entities under common control, Regency's results have been recast to retrospectively consolidate SUGS beginning March 26, 2012. Therefore, the eliminations also include the results of SUGS from March 26, 2012 to April 30, 2013.

- ETP's Segment Adjusted EBITDA reflected the results of Trunkline LNG prior to the Trunkline LNG Transaction, which was effective January 1, 2014. The Investment in Trunkline LNG segment reflected the results of operations of Trunkline LNG. Consequently, the results of operations of Trunkline LNG were reflected in two segments beginning March 26, 2012. Therefore, the results of Trunkline LNG were included in eliminations beginning March 26, 2012.

	Years Ended December 31,		
	2013	2012	2011
Revenues:			
Investment in ETP:			
Revenues from external customers	$ 46,210	$ 15,671	$ 6,761
Intersegment revenues	129	31	38
	46,339	15,702	6,799
Investment in Regency:			
Revenues from external customers	2,404	1,986	1,426
Intersegment revenues	117	14	8
	2,521	2,000	1,434
Investment in Trunkline LNG:			
Revenues from external customers	216	166	—
Intersegment revenues	—	—	—
	216	166	—
Adjustments and Eliminations:	(741)	(904)	(43)
Total revenues	$ 48,335	$ 16,964	$ 8,190
Costs of products sold:			
Investment in ETP	$ 41,204	$ 12,266	$ 4,175
Investment in Regency	1,793	1,387	1,013
Adjustments and Eliminations	(443)	(565)	(19)
Total costs of products sold	$ 42,554	$ 13,088	$ 5,169
Depreciation and amortization:			
Investment in ETP	1,032	656	405
Investment in Regency	287	252	169
Investment in Trunkline LNG	39	30	—
Corporate and Other	16	14	12
Adjustments and Eliminations	(61)	(81)	—
Total depreciation and amortization	$ 1,313	$ 871	$ 586

	Years Ended December 31,		
	2013	2012	2011
Equity in earnings of unconsolidated affiliates:			
Investment in ETP	$ 172	$ 142	$ 26
Investment in Regency	135	105	120
Adjustments and Eliminations	(71)	(35)	(29)
Total equity in earnings of unconsolidated affiliates	$ 236	$ 212	$ 117

	Years Ended December 31,		
	2013	2012	2011
Segment Adjusted EBITDA:			
Investment in ETP	$ 3,953	$ 2,744	$ 1,781
Investment in Regency	608	517	420
Investment in Trunkline LNG	187	135	—
Corporate and Other	(43)	(52)	(29)
Adjustments and Eliminations	(338)	(239)	(41)
Total Segment Adjusted EBITDA	4,367	3,105	2,131
Depreciation and amortization	(1,313)	(871)	(586)
Interest expense, net of interest capitalized	(1,221)	(1,018)	(740)
Bridge loan related fees	—	(62)	—
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Goodwill impairment	(689)	—	—
Gains (losses) on interest rate derivatives	53	(19)	(78)
Non-cash unit-based compensation expense	(61)	(47)	(42)
Unrealized gains on commodity risk management activities	48	10	7
Losses on extinguishments of debt	(162)	(123)	—
LIFO valuation adjustments	3	(75)	—
Adjusted EBITDA related to discontinued operations	(76)	(99)	(23)
Adjusted EBITDA related to unconsolidated affiliates	(727)	(647)	(231)
Equity in earnings of unconsolidated affiliates	236	212	117
Non-operating environmental remediation	(168)	—	—
Other, net	(2)	14	(7)
Income from continuing operations before income tax expense	$ 375	$ 1,437	$ 548

	December 31,		
	2013	2012	2011
Total assets:			
Investment in ETP	$ 43,702	$ 43,230	$ 15,519
Investment in Regency	8,782	8,123	5,568
Investment in Trunkline LNG	1,338	1,917	—
Corporate and Other	720	707	470
Adjustments and Eliminations	(4,212)	(5,073)	(660)
Total	$ 50,330	$ 48,904	$ 20,897

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	Years Ended December 31,		
	2013	2012	2011
Additions to property, plant and equipment, net of contributions in aid of construction costs (accrual basis):			
Investment in ETP	$ 2,455	$ 3,049	$ 1,484
Investment in Regency	1,034	560	406
Investment in Trunkline LNG	2	4	—
Adjustments and Eliminations	(2)	(128)	—
Total	$ 3,489	$ 3,485	$ 1,890

	December 31,		
	2013	2012	2011
Advances to and investments in affiliates:			
Investment in ETP	$ 4,436	$ 3,502	$ 201
Investment in Regency	2,097	2,214	1,925
Adjustments and Eliminations	(2,519)	(979)	(629)
Total	$ 4,014	$ 4,737	$ 1,497

The following tables provide revenues, grouped by similar products and services, for our reportable segments. These amounts include intersegment revenues for transactions between ETP and Regency.

Investment in ETP

	Years Ended December 31,		
	2013	2012	2011
Intrastate Transportation and Storage	$ 2,250	$ 2,012	$ 2,398
Interstate Transportation and Storage	1,270	1,109	447
Midstream	1,307	1,757	1,082
NGL Transportation and Services	2,063	619	363
Investment in Sunoco Logistics	16,480	3,109	—
Retail Marketing	21,004	5,926	—
All Other	1,965	1,170	2,509
Total revenues	46,339	15,702	6,799
Less: Intersegment revenues	129	31	38
Revenues from external customers	$ 46,210	$ 15,671	$ 6,761

Investment in Regency

	Years Ended December 31,		
	2013	2012	2011
Gathering and Processing	$ 2,287	$ 1,797	$ 1,226
Natural Gas Transportation	1	1	1
Contract Services	215	183	190
Corporate and others	18	19	17
Total revenues	2,521	2,000	1,434
Less: Intersegment revenues	117	14	8
Revenues from external customers	$ 2,404	$ 1,986	$ 1,426

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Investment in Trunkline LNG

Trunkline LNG's revenues of $216 million for the year ended December 31, 2013 and $166 million for the period from March 26, 2012 to December 31, 2012 were related to LNG terminalling.

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. Earnings per unit are computed on a stand-alone basis for each quarter and total year. ETP's ETC OLP business is seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

	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 margin	1,372	1,498	1,422	1,489	5,781
Operating income (loss)	531	644	529	(153)	1,551
Net income (loss)	322	338	356	(701)	315
Limited Partners' interest in net income (loss)	90	127	150	(171)	196
Basic net income (loss) per limited partner unit	$ 0.16	$ 0.23	$ 0.27	$ (0.31)	$ 0.35
Diluted net income (loss) per limited partner unit	$ 0.16	$ 0.23	$ 0.27	$ (0.31)	$ 0.35

The three months ended December 31, 2013 was impacted by ETP's recognition of a goodwill impairment of $689 million.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2012:					
Revenues	$ 1,669	$ 1,875	$ 2,107	$ 11,313	$ 16,964
Gross margin	654	916	876	1,430	3,876
Operating income	183	367	358	452	1,360
Net income (loss)	961	75	(34)	272	1,274
Limited Partners' interest in net income	166	53	35	48	302
Basic net income per limited partner unit	$ 0.37	$ 0.10	$ 0.06	$ 0.09	$ 0.57
Diluted net income per limited partner unit	$ 0.36	$ 0.10	$ 0.06	$ 0.09	$ 0.57

17. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of the Parent Company, which are included to provide additional information with respect to the Parent Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS

	December 31,	
	2013	2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8	$ 9
Accounts receivable from related companies	5	11
Other current assets	—	3
Total current assets	13	23
ADVANCES TO AND INVESTMENTS IN AFFILIATES	3,841	6,094
INTANGIBLE ASSETS, net	14	19
NOTE RECEIVABLE FROM AFFILIATE	—	166
GOODWILL	9	9
OTHER NON-CURRENT ASSETS, net	41	56
Total assets	$ 3,918	$ 6,367
LIABILITIES AND PARTNERS' CAPITAL		

CURRENT LIABILITIES:		
Accounts payable	$ —	$ 1
Accounts payable to related companies	11	15
Interest payable	24	48
Price risk management liabilities	—	5
Accrued and other current liabilities	3	1
Current maturities of long-term debt	—	4
Total current liabilities	38	74
LONG-TERM DEBT, less current maturities	2,801	3,840
PREFERRED UNITS	—	331
OTHER NON-CURRENT LIABILITIES	1	9
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL:		
General Partner	(3)	—
Limited Partners – Common Unitholders (559,923,300 and 559,911,216 units authorized, issued and outstanding at December 31, 2013 and 2012, respectively)	1,066	2,125
Class D Units (1,540,000 units authorized, issued and outstanding at December 31, 2013)	6	—
Accumulated other comprehensive income (loss)	9	(12)
Total partners' capital	1,078	2,113
Total liabilities and partners' capital	$ 3,918	$ 6,367

STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2013	2012	2011
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ (56)	$ (53)	$ (30)
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(210)	(235)	(164)
Bridge loan related fees	—	(62)	—
Equity in earnings of unconsolidated affiliates	617	666	509
Gains (losses) on interest rate derivatives	9	(15)	—
Loss on extinguishment of debt	(157)	—	—
Other, net	(8)	(4)	(5)
INCOME BEFORE INCOME TAXES	195	297	310
Income tax benefit	(1)	(7)	—
NET INCOME	196	304	310
GENERAL PARTNER'S INTEREST IN NET INCOME	—	2	1
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 196	$ 302	$ 309

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2013	2012	2011
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 768	$ 555	$ 469
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions	—	(1,113)	—
Proceeds from Holdco Transaction	1,332	—	—
Contributions to affiliates	(8)	(487)	—
Note receivable from affiliate	—	(221)	—
Payments received on note receivable from affiliate	166	55	—
Net cash provided by (used in) investing activities	1,490	(1,766)	—
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	2,080	2,108	92
Principal payments on debt	(3,235)	(162)	(20)
Distributions to partners	(733)	(666)	(526)
Redemption of Preferred Units	(340)	—	—
Debt issuance costs	(31)	(78)	(24)
Net cash provided by (used in) financing activities	(2,259)	1,202	(478)
DECREASE IN CASH AND CASH EQUIVALENTS	(1)	(9)	(9)

CASH AND CASH EQUIVALENTS, beginning of period	9	18	27
CASH AND CASH EQUIVALENTS, end of period	$ 8	$ 9	$ 18

REPORT OF ERNST & YOUNG LLP, INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

ON FINANCIAL STATEMENTS

To the Board of Directors of

Sunoco Partners LLC and Limited Partners of Sunoco Logistics Partners L.P.

We have audited the accompanying consolidated balance sheets of Sunoco Logistics Partners L.P. (the "Partnership") as of December 31, 2012 (successor), and the related consolidated statements of comprehensive income, equity, and cash flows for the period from October 5, 2012 to December 31, 2012 (successor), the period from January 1, 2012 to October 4, 2012 (predecessor) and the year ended December 31, 2011 (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 financial position of Sunoco Logistics Partners L.P. at December 31, 2012 (successor) and the consolidated results of its operations and its cash flows for the period from October 5, 2012 to December 31, 2012 (successor), the period from January 1, 2012 to October 4, 2012 (predecessor) and the year ended December 31, 2011 (predecessor), in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania

March 1, 2013