Energy Transfer Equity, L.P.
Form 10-K
March 01, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012

OR

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

Commission file number 1-32740
ENERGY TRANSFER EQUITY, L.P.
(Exact name of registrant as specified in its charter)

Delaware	30-0108820
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)
Registrant's telephone number, including area code: (214) 981-0700

Securities registered pursuant to Section 12(b) of the Act:

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

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

The aggregate market value as of June 29, 2012, of the registrant's Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was $8.60 billion. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At February 21, 2013, the registrant had 279,961,650 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

Table of Contents

TABLE OF CONTENTS

Table of Contents

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Equity, L.P. ("ETE," "Energy Transfer Equity," 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," "inten "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
Citrus Acquisition	ETP's acquisition of Citrus Corp. on March 26, 2012
CrossCountry	CrossCountry Energy, LLC
CFTC	Commodities Futures Trading Commission

DRIP	Distribution Reinvestment Plan
DOT	U.S. Department of Transportation
Enterprise	Enterprise Products Partners L.P., together with its subsidiaries
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETG	Energy Transfer Group, L.L.C.
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

Table of Contents

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
Finance Company	AmeriGas Finance LLC
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.
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
MDPU	Massachusetts Department of Public Utilities
MEP	Midcontinent Express Pipeline LLC
MGP	manufactured gas plant
MMBtu	million British thermal units

MMcf	million cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
NMED	New Mexico Environmental Department
NOL	net operating loss
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Other Post-retirement Plans	postretirement health care and life insurance plans
OSHA	Federal Occupational Safety and Health Act
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCB	polychlorinated biphenyl
Pension Plans	funded non-contributory defined benefit pension plans

Table of Contents

PEPL	Panhandle Eastern Pipe Line Company, LP
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
RIGS	Regency Intrastate Gas System
RGS	Regency Gas Services, a wholly owned subsidiary of Regency
Preferred Units	ETE's Series A Convertible Preferred Units
Propane Business	Heritage Operating, L.P. and Titan Energy Partners, L.P.
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Regency GP	Regency Energy Partners GP LP, the general partner of Regency
Regency LLC	Regency Energy Partners GP LLC, the general partner of Regency GP
Regency Preferred Units	Regency's Series A Convertible Preferred Units, the Preferred Units of a Subsidiary
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southern Union Credit Facility	Southern Union's revolving credit facility
Southwest Gas	Pan Gas Storage, LLC
SUGS	Southern Union Gas Services
Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet

Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC
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 of ETP’s Propane Business 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 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 and for unconsolidated affiliates based on the Partnership's proportionate ownership.

Table of Contents

PART I

ITEM 1. 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, Southern Union, Sunoco, Sunoco Logistics and Holdco. References to the “Parent Company” mean Energy Transfer Equity, L.P. on a stand-alone basis.

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.

The Parent Company’s principal sources of cash flow have historically 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. Effective with the acquisition of Southern Union in March 2012, the Parent Company also generated cash flows through its wholly owned subsidiary, Southern Union, until the contribution of Southern Union to Holdco on October 5, 2012. Subsequent to the Holdco Transaction, we also generate cash flows from our direct investment in Holdco.

At December 31, 2012, our interests in ETP and Regency consisted of:

	General Partner Interest (as a % of total partnership interest)		Incentive Distribution Rights (“IDRs”)		Limited Partner Units
ETP	0.9	%	100	%	50,226,967
Regency	1.6	%	100	%	26,266,791

The Parent Company’s primary cash requirements are for distributions to its partners and holders of the Preferred Units, 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.

Table of Contents

Organizational Structure

The following chart summarizes our organizational structure as of December 31, 2012:

Table of Contents

Strategic Transactions

Our significant strategic transactions in 2012 included the following, as discussed in more detail herein:

- On January 12, 2012, ETP contributed its propane operations, consisting of HOLP and Titan (collectively, the “Propane Business”) 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 $1.5 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.5 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.
- On March 26, 2012, we acquired all of the outstanding shares of Southern Union for approximately $3.01 billion in cash and approximately 57 million ETE Common Units. 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 2.25 million ETP Common Units.
- 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 approximately $2.6 billion in cash (the "Sunoco merger").
- Immediately following the closing of the Sunoco merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation, 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 90,706,000 ETP Class F Units representing limited partner interests in ETP. We refer to this as the "Holdco Transaction." Pursuant to a stockholders agreement between ETE and ETP, ETP controls Holdco. Consequently, ETP consolidates Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.
- In December 2012, Southern Union entered into a purchase and sale agreement pursuant to which subsidiaries of Laclede Gas Company, Inc. have agreed to acquire the assets of Southern Union's Missouri Gas Energy and New England Gas Company divisions. Total consideration for the acquisitions will be $1.035 billion, subject to customary closing adjustments, less the assumption of approximately $19 million of debt. On February 11, 2013, the Laclede Entities announced that it had entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that will allow a subsidiary of APUC to assume the right of the Laclede Entities to purchase the assets of Southern Union's New England Gas Company division, subject to certain approvals. It is expected that the transactions contemplated by the purchase and sale agreements will close by the end of the third quarter of 2013.
- On February 27, 2013, Southern Union entered into a definitive contribution agreement to contribute to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration to be paid by Regency in connection with this transaction will consist of (i) the issuance of 31,372,419 Regency common units to Southern Union, (ii) the issuance of 6,274,483 Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units will 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. Upon the closing of the transaction, we will agree to forego all distributions with respect to our IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing. The transaction is expected to close in the second quarter of 2013.

Business Strategy

Our primary business objective is to increase cash available for distributions to our unit holders 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 ETP or Regency the first opportunity to pursue any acquisition or internal growth project that may be presented to us which may be within the scope of ETP and Regency's operations or business strategies. In the future, we may also support the growth of ETP and Regency through the use of our capital resources which could involve loans, capital contributions or other forms of credit support to ETP and Regency. This funding could be used for the acquisition by ETP or Regency of a business or asset or for an internal growth project. In addition, the availability of this capital could assist ETP or Regency in arranging financing for a project, reducing its financing costs or otherwise supporting a merger or acquisition transaction.

Table of Contents

Segment Overview
Subsequent to the Holdco Transaction on October 5, 2012, as described above, our reportable segments changed and currently consist of the following:
- Intrastate Transportation and Storage — consists of assets and operations held by ETP;
- Interstate Transportation and Storage — consists of assets and operations held by ETP and Southern Union;
- Midstream — consists of assets and operations held by ETP and Southern Union;
- NGL Transportation and Services — consists of assets and operations held by ETP and Lone Star;
- Retail Marketing — consists of retail marketing operations held by Sunoco;
- Investment in Sunoco Logistics — consists of ETP's interest in Sunoco Logistics;
- Investment in Regency — consists of the Parent Company's interest in Regency; and
- Corporate and Other — consists of various operations held by multiple subsidiaries, as described below.

The businesses within these segments are described below. See Note 15 to our consolidated financial statements for additional financial information about our reportable segments.
Intrastate Transportation and Storage Segment
Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines and gathering systems and deliver the natural gas to industrial end-users, utilities and other pipelines. Through our intrastate transportation and storage segment, we own and operate approximately 7,800 miles of natural gas transportation pipelines and three natural gas storage facilities located in the state of Texas.
Through ETC OLP, we own the largest intrastate pipeline system in the United States with interconnects to Texas markets and to major consumption areas throughout the United States. Our intrastate transportation and storage segment focuses on the transportation of natural gas to major markets from various prolific natural gas producing areas through connections with other pipeline systems as well as through our Oasis pipeline, our East Texas pipeline, our natural gas pipeline and storage assets that we refer to as ET Fuel System, and our HPL System, which are described below.
Our intrastate transportation and storage segment’s results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.
We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on our HPL System. Generally, we purchase natural gas from either the market (including purchases from our midstream segment’s marketing operations) or from producers at the wellhead. To the extent the natural gas comes from producers, it is primarily purchased at a discount to a specified market price and typically resold to customers based on an index price. In addition, our intrastate transportation and storage segment generates revenues from fees charged for storing customers’ working natural gas in our storage facilities and from margin from managing natural gas for our own account. The major customers on our intrastate pipelines include Kinder Morgan, Natural Gas Exchange, Inc., XTO Energy, Inc., Total Gas & Power North America and EDF Trading North America, Inc.
Interstate Transportation and Storage Segment
Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines and gathering systems and deliver the natural gas to industrial end-users, utilities and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 12,700 miles of interstate natural gas pipeline and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline. ETP also owns a 50% interest in Citrus which owns 100% of FGT, an approximately 5,400 mile pipeline system that extends from south Texas through the Gulf Coast to south Florida.
Our interstate transportation and storage segment includes Panhandle, a wholly owned subsidiary of Southern Union, which is owned by Holdco. Panhandle owns and operates a large natural gas open-access interstate pipeline

network. The pipeline network,

7

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. Through Trunkline LNG, Panhandle owns and operates an LNG terminal in Lake Charles, Louisiana.
The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services. The major customers on our interstate pipelines include Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. (“EnCana”), Shell Energy North America (US), L.P., BG LNG Services, ProLiance Energy, LLC and Petrohawk Energy Corporation.
We are currently developing plans to convert existing pipeline assets from natural gas transportation to crude oil transportation. These plans include the proposed abandonment of certain pipeline segments of Trunkline Gas Company, LLC (“Trunkline”), a subsidiary of Southern Union, which are currently operating in natural gas service, and the conversion of some or all of those segments of pipeline to crude oil transportation service. Trunkline's application to abandon those segments of pipeline from natural gas service, filed July 26, 2011, is currently pending before the FERC. As of February 13, 2013, the Partnership and Enbridge (U.S.), Inc. entered into an agreement under which they will jointly market a project to transport up to 400,000 Bbls/d of crude oil from Patoka, Illinois, to refinery markets in and around Memphis, Tennessee, Baton Rouge, Louisiana, and St. James, Louisiana, utilizing a combination of newly constructed pipeline and approximately 574 miles of pipeline to be abandoned by Trunkline. Subject to receipt of sufficient customer commitments for long-term transportation capacity and regulatory approvals, this project is expected to be in service by 2015.
We are currently studying the commercial and engineering feasibility of constructing a liquefaction facility at Southern Union's existing Lake Charles LNG regasification terminal. The project is anticipated to utilize a portion of the existing LNG regasification infrastructure, including storage tanks and terminal facilities, and is expected to have the capacity to export up to 2.0 Bcf/d of LNG. We are currently in commercial negotiations with counterparties. We expect to complete certain studies, permits and approvals through 2014, and we do not anticipate making any significant capital expenditures related to this project prior to the completion of those items.
Midstream Segment
The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets. The midstream industry consists of natural gas gathering, compression, treating, processing and transportation, and is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.
The natural gas gathering process begins with the drilling of wells into gas-bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural gas from points near producing wells and transport it to larger pipelines for further transportation.
Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Field compression is typically used to lower the pressure of a gathering system. If field compression is not installed, then the remaining production in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise might not be produced.
Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is higher in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove carbon dioxide and hydrogen sulfide from natural gas to ensure that it meets pipeline quality specifications.
Some natural gas produced by a well does not meet the pipeline quality specifications established by downstream pipelines or is not suitable for commercial use and must be processed to remove the mixed NGL stream. In addition,

some natural gas produced by a well, while not required to be processed, can be processed to take advantage of favorable processing margins. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream.

Through our midstream segment, we own and operate approximately 6,700 miles of in service natural gas and NGL gathering pipelines, 4 natural gas processing plants, 15 natural gas treating facilities and 3 natural gas conditioning facilities. Our midstream segment focuses on the gathering, compression, treating, blending, processing and marketing of natural gas, and our operations are currently concentrated in major producing basins and shales, including the Austin Chalk trend and Eagle Ford Shale in South

Table of Contents

and Southeast Texas, the Permian Basin in West Texas and New Mexico, the Barnett Shale and Woodford Shale in North Texas, the Bossier Sands in East Texas, the Marcellus Shale in West Virginia, and the Haynesville Shale in East Texas and Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment results are derived primarily from margins we earn for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems and the natural gas and NGL volumes processed at our processing and treating facilities. We also market natural gas on our pipeline systems in addition to other pipeline systems to realize incremental revenue on gas purchased, increase pipeline utilization and provide other services that are valued by our customers. The major customers on our midstream pipelines include Enterprise, ConocoPhillips Company, Andrews Oil Buyers, Inc. and Chevron Phillips Chemical Company LP.

SUGS' operations consist of a network of natural gas and NGL pipelines, six processing plants and seven natural gas treating facilities. The principal assets of SUGS are located in the Permian Basin of Texas and New Mexico.

SUGS is primarily engaged in connecting producing wells of exploration and production companies to its gathering system, providing compression and gathering services, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGL, and redelivering natural gas and NGLs to a variety of markets. SUGS' natural gas supply contracts primarily include fee-based, percent-of-proceeds, and margin sharing contracts (conditioning fee and wellhead purchase contracts). SUGS' primary sales customers include E&P companies, power generating companies, electric and natural gas utilities, energy marketers, industrial end-users located primarily in the Gulf Coast and southwestern United States, and petrochemicals. With respect to customer demand for the products and services it provides, SUGS' business is not generally seasonal in nature; however, SUGS' operations and the operations of its E&P producers can be adversely impacted by severe weather.

NGL Transportation and Services Segment

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

Through our NGL transportation and services segment we own and operate approximately 300 miles of NGL pipelines and have a 50% interest in the Liberty pipeline, an approximately 85-mile NGL pipeline. ETP also has a 70% interest in Lone Star and Regency owns the remaining 30% interest, which owns approximately 2,000 miles of NGL pipelines, three NGL processing plants, two fractionation facilities and NGL storage facilities with aggregate working storage capacity of approximately 47 million Bbls. One of the fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, and the NGL pipelines primarily transport NGLs from the Permian and Delaware basis and the Barnett and Eagle Ford Shales to Mont Belvieu.

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

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

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

Retail Marketing

Our retail marketing and wholesale distribution business segment consists of Sunoco's marketing operations, which sell gasoline and middle distillates at retail and operates convenience stores in 25 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.

Investment in Sunoco Logistics

The Partnership's interests in Sunoco Logistics consist of a 2% general partner interest, 100% of the incentive distribution rights and 33,530,637 Sunoco Logistics Common Units representing 32% of the limited partner interests in Sunoco Logistics as of December 31, 2012. Because the Partnership controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into the Partnership. These operations are reflected by the Partnership in the investment in Sunoco Logistics segment.

Sunoco Logistics' crude oil pipelines transport crude oil principally in Oklahoma and Texas. Crude oil transportation pipelines primarily deliver to and connect with other pipelines that deliver crude oil to a number of third-party refineries. 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 200 crude oil transport trucks, approximately 120 crude oil truck unloading facilities and third-party assets.

Sunoco Logistics' refined terminal facilities receive refined products from pipelines, barges, railcars and trucks and transfer them to or from storage or transportation systems, such as pipelines, to other transportation systems, such as trucks or other pipelines. Sunoco Logistics' terminal facilities consist of an aggregate crude oil and refined petroleum products capacity of approximately 40 million barrels, including the 22 million barrel Nederland, Texas crude oil terminal; the 5 million barrel Eagle Point, New Jersey refined petroleum products and crude oil terminal; approximately 40 active refined petroleum 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.

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 and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes 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.

Natural Gas Transportation Operations

Regency owns a 49.99% general partners 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 an interstate natural gas pipeline with approximately 500 miles stretching from Southeast Oklahoma through Northwest Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama.

Table of Contents

This segment also includes 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, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in the states of Texas, Mississippi and Louisiana. ETP owns the remaining 70%.

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, dehydration and BTU management, to natural gas producers and midstream pipeline companies.

All Other

Segments below the quantitative thresholds are classified as “Corporate and Other.” These include the following:

- activities of the Parent Company;
- 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.; and
- ETP's corporate and other, which includes the following operating segments that do not meet the qualitative threshold for separate reporting:

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 our other segments.

- We own all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- ETP owns a 32% limited partner interest in AmeriGas, which is engaged in retail propane marketing. ETP acquired this interest when it contributed its retail propane operations to AmeriGas in January 2012.
- Southern Union has operations providing local distribution of natural gas in Missouri and Massachusetts. The operations are conducted through the Southern Union’s operating divisions: Missouri Gas Energy and New England Gas Company. As noted in "Strategic Transactions" above, we recently entered into an agreement to sell these operations.
- Sunoco owns approximately 30% non-operating interest in Philadelphia Energy Solutions (“PES”), a joint venture with The Carlyle Group, L.P. (“The Carlyle Group”), which owns a refinery in Philadelphia. Sunoco has a ten-year supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

Asset Overview

Intrastate Transportation and Storage Segment

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

ET Fuel System

- Capacity of 5.2 Bcf/d
- Approximately 2,875 miles of natural gas pipeline
- Two storage facilities with 12.4 Bcf of total working gas capacity
- Bi-directional capabilities

The ET Fuel System serves some of the most active drilling areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. With approximately 550 receipt and/or delivery points, including interconnects with pipelines providing direct access to power plants and interconnects with other intrastate and interstate pipelines, the ET Fuel System is strategically located near high-growth production areas and provides access to the Waha Hub near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas. The major

Table of Contents

shippers on our pipelines include EOG Resources, Inc., Chesapeake Energy Marketing, Inc., XTO Energy, Inc. ("XTO"), Luminant Energy Company LLC, and EnCana.

The ET Fuel System also includes our Bethel natural gas storage facility, with a working capacity of 6.4 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. All of our storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2017.

In addition, the ET Fuel System is integrated with our Godley processing plant which gives us the ability to bypass the plant when processing margins are unfavorable by blending the untreated natural gas from the North Texas System with natural gas on the ET Fuel System while continuing to meet pipeline quality specifications.

Oasis Pipeline

- Capacity of 1.2 Bcf/d
- Approximately 600 miles of natural gas pipeline
- Connects Waha to Katy market hubs
- Bi-directional capabilities

The Oasis pipeline is primarily a 36-inch natural gas pipeline. It has bi-directional capability with approximately 1.2 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis pipeline has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

The Oasis pipeline is integrated with our Southeast Texas System and is an important component to maximizing our Southeast Texas System's profitability. The Oasis pipeline enhances the Southeast Texas System by (i) providing access for natural gas on the Southeast Texas System to other third party supply and market points and interconnecting pipelines and (ii) allowing us to bypass our processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

HPL System

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

The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The HPL System is well situated to gather and transport gas in many of the major gas producing areas in Texas including the strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, and our Bammel storage facility.

The Bammel storage facility has a total working gas capacity of approximately 62 Bcf, a peak withdrawal rate of 1.3 Bcf/d and a peak injection rate of 0.6 Bcf/d. The Bammel storage facility is located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers. As of December 31, 2012, we had approximately 12.4 Bcf committed under fee-based arrangements with third parties and approximately 45.7 Bcf stored in the facility for our own account.

East Texas Pipeline

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

The East Texas pipeline connects three treating facilities, one of which we own, with our Southeast Texas System. The East Texas pipeline was the first phase of a multi-phased project that increased service to producers in East and North Central Texas and provided access to the Katy Hub. The East Texas pipeline expansions include the 36-inch

East Texas extension to connect our Reed compressor station in Freestone County to our Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting our Cleburne to Carthage pipeline to the HPL

Table of Contents

System. Key shippers on the East Texas pipeline include XTO and EnCana with an average of approximately 680,000 MMBtu/d and 260,000 MMBtu/d, respectively.

Interstate Transportation Pipelines

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

Florida Gas Transmission Pipeline

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

The Florida Gas Transmission pipeline is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,400 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The Florida Gas Transmission pipeline system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering over 64% of the natural gas consumed in the state. In addition, Florida Gas Transmission's pipeline system operates and maintains over 70 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 2.0 Bcf/d
- Approximately 2,560 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 Pipeline

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

The Panhandle Eastern pipeline’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 pipeline 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

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.

Table of Contents

Tiger Pipeline

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

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

Fayetteville Express Pipeline

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

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

Sea Robin Pipeline

- Capacity of 1.9 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 81 miles into the Gulf of Mexico. Sea Robin pipeline is owned by a subsidiary of Holdco.

Midstream

The following details our assets in the midstream segment.

Southeast Texas System

- Approximately 6,200 miles of natural gas pipeline
- One natural gas processing plant (La Grange) with aggregate capacity of 205 MMcf/d
- 12 natural gas treating facilities with aggregate capacity of 1.8 Bcf/d
- One natural gas conditioning facility with aggregate capacity of 200 MMcf/d

The Southeast Texas System is an integrated system that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the East Texas pipeline and is connected to the Oasis pipeline, as well as two power plants. This allows us to bypass our processing plants and treating facilities when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with natural gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

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

Our treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications. In addition, our conditioning facilities remove heavy hydrocarbons from the gas gathered into our systems so the gas can be redelivered and meet downstream pipeline hydrocarbon dew point specifications.

Table of Contents

SUGS

- Approximately 5,700 miles of natural gas and NGL pipelines
- Six processing plants with aggregate capacity of 510 MMcf/d

Seven natural gas treating facilities with aggregate capacity of 630 MMcf/d

SUGS owns natural gas and NGL pipelines, processing plants and natural gas treating plants and is engaged in connecting producing wells of exploration and production companies to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs and redelivering natural gas and NGLs to a variety of markets in West Texas and New Mexico. SUGS is owned by a subsidiary of Holdco.

North Texas System

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

The North Texas System is an integrated system located in four counties in North Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett and Woodford Shales. The system includes our Godley processing plant, which processes rich natural gas produced from the Barnett Shale and is integrated with the North Texas System and the ET Fuel System. The facility consists of a processing plant and a conditioning facility.

Northern Louisiana

- Approximately 280 miles of natural gas pipeline
- Three natural gas treating facilities with aggregate capacity of 385 MMcf/d

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

Rich Eagle Ford Mainline System

- Approximately 220 miles of natural gas pipeline
- Two processing plants (Chisholm and Kenedy) with capacity of 325 MMcf/d

The Rich Eagle Ford Mainline gathering system consists of 30-inch and 42-inch natural gas transportation pipelines delivering 1.0 Bcf/d of capacity originating in Dimmitt County, Texas and extending to our Chisholm pipeline for ultimate deliveries to our existing processing plants. Our Chisholm and Kenedy processing plants are connected to our intrastate transportation pipeline systems for deliveries of residue gas and are also connected with our NGL pipelines for delivery of NGLs.

Other Midstream Assets

The midstream segment also includes our interests in various midstream assets located in Texas, New Mexico and Louisiana, with gathering pipelines aggregating a combined capacity of approximately 115 MMcf/d, as well as one conditioning facility. We also own gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

Marketing Operations

We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation.

For the off-system gas, we purchase gas or act as an agent for small independent producers that may not have marketing operations. We develop relationships with natural gas producers to facilitate the purchase of their production on a long-term basis. We believe that this business provides us with strategic insight and market intelligence, which may positively impact our expansion and acquisition strategy.

Table of Contents

NGL Transportation and Services
The following details our assets in the NGL transportation and services segment. Certain assets described below are owned by Lone Star, a joint venture with ETP and Regency owning 70% and 30% interests, respectively.
West Texas System
- Capacity of 137,000 Bbls/d
- Approximately 1,170 miles of NGL transmission pipelines

The West Texas System, owned by Lone Star, is an intrastate NGL pipeline consisting of 3-inch to 16-inch long-haul, mixed NGLs transportation pipeline that delivers 137,000 Bbls/d of capacity from the Regency Waha Processing Plant in the Permian Basin and our Godley Processing Plant in the Barnett Shale to the Mont Belvieu NGL storage facility.
West Texas Gateway Pipeline
- Initial 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 in West Texas and the Eagle Ford Shale to Mont Belvieu, Texas.
Other NGL Pipelines
- Capacity ranging from 20,000 to 260,000 Bbls/d
- Approximately 279 miles of NGL transmission pipelines

Other NGL pipelines include the 126-mile Justice pipeline with capacity of 260,000 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 21-mile Spirit pipeline with a capacity of 20,000 Bbls/d.
Mont Belvieu Storage Facilities
- Working storage capacity of approximately 43 million Bbls
- Approximately 140 miles of NGL transmission pipelines
- 100,000 Bbls/d fractionation facility

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 Long Star Fractionator I, completed in December 2012, handles NGLs delivered from several sources, including Lone Star's West Texas Gateway pipeline and the Justice pipeline.
Hattiesburg Storage Facility
- Working storage capacity of 4 million Bbls

The Hattiesburg storage facility 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 a total 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.

Table of Contents

Refinery Services

- Two processing plants (the Chalmette and Sorrento Plants) with a total capacity of 82 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 Sorrento and Chalmette processing plants.

Retail Marketing

The retail marketing segment consists of the retail sale of gasoline and middle distillates and the operation of convenience stores in 25 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 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. These sites may be traditional locations that sell fuel products under the Sunoco® and Coastal® brands or may include APlus® convenience stores or Ultra Service Centers® that provide automotive diagnostics and repair. Included among the direct outlets at December 31, 2012 were 73 outlets on turnpikes and expressways in Pennsylvania, New Jersey, New York, Maryland, Ohio and Delaware. Of these outlets, 57 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 Sunoco's retail gasoline outlets at December 31, 2012:

Direct Outlets:	
Sunoco-Owned or Leased:	
Sunoco Operated:	
Traditional	60
APlus® Convenience Stores	377
	437
Dealer Operated:	
Traditional	127
APlus® Convenience Stores	233
Ultra Service Centers®	91
	451
Total Sunoco-Owned or Leased (1)	888
Dealer Owned (2)	495
Total Direct Outlets	1,383
Distributor Outlets	3,605
	4,988

(1) Gasoline and diesel throughput per Sunoco-operated site averaged 198,000 gallons per month from the merger date.

(2) Primarily traditional outlets.

Branded fuels sales (including middle distillates) averaged 318,000 Bbls/d from the merger date.

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,

Table of Contents

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, 2012:

Number of stores	377	
Merchandise sales (thousands of dollars/store/month)	$106	
Merchandise margin (% sales)	26	%

Investment in Sunoco Logistics

Sunoco Logistics is principally engaged in the transport, terminalling and storage of crude oil and refined petroleum products. In addition to logistics services, Sunoco Logistics owns acquisition and marketing assets which are used to facilitate the purchase and sale of crude oil and refined products. Its portfolio of geographically diverse assets earns revenues in 30 states located throughout the United States. Sunoco Logistics also has an ownership interest in several refined product and crude oil pipeline joint ventures.

The following details the assets owned by 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:

- West Texas Gulf Pipe Line Company owns approximately 600 miles of common carrier crude oil pipelines, which originate from the West Texas oil fields at Colorado City and the Nederland Terminal and extend to Longview, Texas where deliveries are made to several pipelines, including the Mid-Valley pipeline.
- Mid-Valley Pipeline Company owns approximately 1,000 miles of crude oil pipelines, which originate in Longview, Texas and terminate in Samaria, Michigan. Mid-Valley provides crude oil to a number of refineries, primarily in the midwest United States.
- The Southwest United States pipeline system consists of approximately 2,950 miles of crude oil trunk pipelines and approximately 300 miles of crude oil gathering pipelines in Texas. The Texas system is connected to the Mid-Valley pipeline, the West Texas Gulf pipeline, other third-party pipelines and our Nederland Terminal.
- The Oklahoma crude oil pipeline and gathering system contains approximately 850 miles of crude oil trunk pipelines and approximately 200 miles of crude oil gathering pipelines. We have the ability to deliver substantially all of the crude oil gathered on our Oklahoma system to Cushing.
- The Midwest United States pipeline system 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.

Sunoco Logistics' pipelines access several trading hubs, including the largest trading hub for crude oil in the United States located in Cushing, Oklahoma, as well as other trading hubs located in Midland, Colorado City and Longview, Texas. Our crude oil pipelines also deliver to and connect with other pipelines that deliver crude oil to a number of third-party refineries.

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. Sunoco Logistics' crude oil truck drivers pick up crude oil at production lease sites and transport it to various truck unloading facilities on our pipelines and third-party pipelines. Third-party trucking firms are also retained to transport crude oil to certain facilities.

Table of Contents

Terminal Facilities

Sunoco Logistics' 41 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.

- The East Boston Terminal is a refined products terminal, located in East Boston, Massachusetts, that receives refined products from affiliates of ConocoPhillips. The terminal is the sole service provider to Logan International Airport under a long-term contract to provide jet fuel. The terminal includes a 10-bay truck rack and total active storage capacity for this facility is approximately 1 million barrels.
- The Eagle Point Tank farm is located in Westville, New Jersey and consists of approximately 5 million barrels of active storage for clean products and dark oils.
- The Southwest Terminal is a crude oil and refined products terminal located in Bay City, Texas. The terminal has a total capacity of less than half of a million barrels.
- A butane blending business generates profits by adding less expensive normal butane to higher priced gasoline, while complying with regional and seasonally variable specifications for maximum vapor pressure. The business provides terminal and pipeline operators with the use of proprietary automated blending systems and butane supply to optimize butane blending in pipelines and at refined products terminals.

Sunoco Logistics' refined products terminals derive revenues from terminalling fees paid by customers. A fee is charged for receiving refined products into the terminal and delivering them to trucks, barges, or pipelines. In addition to terminalling fees, Sunoco Logistics generates revenues by charging customers fees for blending services, including ethanol and biodiesel blending, injecting additives, and filtering jet fuel. Sunoco Logistics' refined products pipelines supply the majority of its refined products terminals, with third-party pipelines and barges supplying the remainder.

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
Maryland	1	715
Massachusetts	1	1,160
Michigan	3	762
New Jersey	4	746
New York (1)	4	920
Ohio	7	904
Pennsylvania	13	1,734
Virginia	1	403
Louisiana	1	161
Texas	5	715
Total	41	8,426

(1) Sunoco Logistics owns 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.

Sunoco Logistics' 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 aboveground storage tanks with individual capacities of up to 660,000 barrels.

Table of Contents

Sunoco Logistics' Fort Mifflin Terminal Complex is located on the Delaware River in Philadelphia 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.

Sunoco Logistics' Marcus Hook tank farm has a total storage capacity of approximately 2 million barrels.

Sunoco Logistics' Eagle Point Terminal docks are located in Westville, New Jersey on the Delaware River and are connected to the Sunoco Eagle Point refinery, which was permanently shut down in the fourth quarter 2009. To complement the services offered by Sunoco Logistics' existing dock and truck loading equipment, Sunoco Logistics acquired the Eagle Point tank farm from Sunoco in July 2011. The tank farm is connected to Sunoco Logistics' previously owned dock facility and allowed us to expand upon the services offered by its existing assets. The tank farm provides crude oil and refined products storage and distribution services and has a total active storage capacity of approximately 5 million barrels for clean products and dark oils. The docks can accommodate three ships or barges to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges.

Sunoco Logistics' 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.

Refined Products Pipelines

Sunoco Logistics owns and operates approximately 2,500 miles of refined products pipelines in selected areas of the United States. The refined products pipelines transport refined products from refineries in the northeast, midwest and southwest United States to markets in New York, New Jersey, Pennsylvania, Ohio, Michigan, Massachusetts, Texas and Canada. 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). 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 is Sunoco Logistics' 83.8% owned joint venture consisting of 350 miles of active refined products pipelines in Ohio. The pipeline connects three refineries in Ohio to terminals and major markets in Ohio. 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 Lake Charles, Louisiana and 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.

Sunoco has agreements with Sunoco Logistics which establish fees for administrative services provided by Sunoco to Sunoco Logistics and provide indemnifications by Sunoco for certain environmental, toxic tort and other liabilities.

Table of Contents

Investment in Regency

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

Gathering and Processing Operations

North Louisiana Region

- Approximately 653 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.

In August 2012, Regency announced construction of an expansion of the Dubach processing facility in North Louisiana that will increase the processing capacity of the facility to 210 MMcf/d by adding an incremental 70 MMcf/d of cryogenic processing capacity and 20 MMcf/d of JT capacity. The $75 million capital expenditure related to this expansion also includes the construction of high-pressure gathering lines to bring production to the facility. The project, which is expected to come online in the second quarter of 2013, is backed by fee-based contracts and an acreage dedication.

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

South Texas Region

- Approximately 1,286 miles of natural gas pipeline
- Two treating plants

Regency’s South Texas assets gather, compress, treat and dehydrate natural gas in 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.

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 NGL-rich Eagle Ford Shale formation, which lies directly under Regency’s existing South Texas gathering system infrastructure.

One of Regency’s treating plants consists of inlet gas compression, a 60 MMcf/d amine treating unit, a 55 MMcf/d amine treating unit and a 40 ton (per day) liquid sulfur recovery unit. This plant removes hydrogen sulfide from the natural gas stream, recovers condensate, delivers pipeline quality gas at the plant outlet and reinjects acid gas. In January 2012, Regency completed an expansion of the treating plant, adding an incremental 20 MMcf/d of treating capacity to the facility.

In June 2011, Regency entered into agreements to provide gas and condensate gathering services for a producer in the Eagle Ford Shale and to construct facilities to perform these services, including a wellhead gathering system, at an expected cost of approximately $450 million. The expansion will be owned and operated by Regency and will connect with its existing gathering system. The expansion is scheduled to be completed in phases by 2014. Upon its completion, Regency’s entire South Texas system will be capable of gathering, compressing, treating and transporting up to 1 Bcf/d of natural gas and 26,500 Bbls/d of condensate to downstream outlets.

Regency owns a 60% interest in an entity that includes a treating plant in Atascosa County with a 500 gallons per minute amine treater, pipeline interconnect facilities and approximately 13 miles of 10-inch pipeline. Tailsman Energy USA Inc. and Statoil Texas Onshore Properties LP own the remaining 40% interest. Regency operates this plant and the pipeline for the joint venture while its joint venture partner operates a lean gas gathering system in the Edwards Lime natural gas trend that delivers to this system. In May 2012, Regency announced the construction of an expansion which will increase the system's capacity by 90 MMcf/d to 160 MMcf/d, and will provide for additional crude transportation and stabilization capacity of 17,000 Bbls/d. Contracts on the expansion are fee-based, which includes reservation fees. Capital expenditures related to the expansion are expected to total $150 million, of which Regency will contribute $90 million. The project is expected to be completed in mid-2012.

21

Table of Contents

West Texas Region
- Approximately 941 miles of natural gas pipeline
- Two cryogenic natural gas processing plants and a refrigeration plant

Regency's West Texas gathering system assets offer wellhead-to-market services to producers in Ward, Winkler, Reeves, and Pecos counties, which surround the Waha Hub, one of Texas' major NGL-rich natural gas market areas. As a result of the proximity of Regency's system to the Waha Hub, the Waha gathering system has a variety of market outlets for the natural gas that Regency gathers and processes, including several major interstate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets. The NGL market outlets include Lone Star's West Texas NGL pipeline.

Regency offers producers four different levels of natural gas compression on the Waha gathering system, 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 its producers, since the producer is typically not required to pay for a level of compression that is higher than the level they require.

The Waha cryogenic natural gas processing plant processes raw natural gas gathered in the Waha gathering system. The Waha processing plant also includes an amine treating facility, which removes carbon dioxide and hydrogen sulfide from raw natural gas gathered before moving the natural gas to the processing plant. The acid gas is injected underground.

Regency also owns a 33.33% 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 3,465 miles of natural gas pipeline
- One processing plant

Regency's mid-continent systems are located in two of the largest and most prolific 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 approximately 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 approximately 1,875 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

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.

Regency owns a 50% membership interest in MEP, which owns an interstate natural gas pipeline with approximately 500 miles 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.

Regency also owns a 10-mile pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

NGL Services Operations

Regency owns a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including NGL pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.

Contract Services Operations

The natural gas contract compression operations include designing, sourcing, owning, installing, operating, servicing, repairing and maintaining compressors and related equipment for which Regency guarantees its 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

Table of Contents

involve long-term installations of multiple large horsepower compression units. Regency's contract compression operations are primarily located in Texas, Louisiana, Arkansas, Pennsylvania 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, to natural gas producers and midstream pipeline companies. Regency's contract treating operations are primarily located in Texas, Louisiana and Arkansas.

Industry Overview

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets. The midstream industry consists of natural gas gathering, compression, treating, processing and transportation and NGL fractionation and transportation, and is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

Natural gas has widely varying quality and composition, depending on the field, the formation or the reservoir from which it is produced. The principal constituents of natural gas are methane and ethane, though most natural gas also contains varying amounts of heavier components, such as propane, butane and natural gasoline that may be removed by a number of processing methods.

Most raw materials produced at the wellhead are not suitable for long-haul pipeline transportation or commercial use and must be compressed, transported via pipeline to a central processing facility, and then processed to remove the heavier hydrocarbon components and other contaminants that would interfere with pipeline transportation or the end use of the gas.

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

Demand for natural gas. Natural gas continues to be a critical component of energy consumption in the United States. According to data released in December 2010 by the Energy Information Administration, total domestic consumption of natural gas is expected to rise to 26.5 Tcf in 2035, compared to 2010 consumption of 24.1 Tcf. The industrial and electricity generation sectors currently account for more than half of natural gas usage in the United States.

Demand for oil. Oil continues to be a critical component of energy consumption in the United States.

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

Natural gas compression. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Field compression is typically used to lower the pressure of a gathering system. If field compression is not installed, then the remaining production in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise might not be produced.

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is higher in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove carbon dioxide and hydrogen sulfide from natural gas to ensure that it meets pipeline quality specifications.

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

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

Table of Contents

NGL transportation. NGL transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities.
NGL storage. NGL storage facilities are used for the storage of mixed NGLs, NGL products and petrochemical products owned by third-parties in storage tanks and underground wells, which allow for the injection and withdrawal of such products at various times of the year to meet demand cycles.
NGL fractionation and processing. NGL fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.
Refined products transportation. 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.
Terminal facilities. Refined terminal facilities receive refined products from pipelines, barges, railcars and trucks and transfer them to or from storage or transportation systems, such as pipelines, to other transportation systems, such as trucks or other pipelines. Terminals play a key role in moving product to the end-user markets by providing the following services: storage, distribution, blending to achieve specified grades of gasoline and middle distillates; and other ancillary services that include the injection of additives and the filtering of jet fuel.
Crude oil transportation. Crude oil transportation pipelines primarily deliver to and connect with other pipelines that deliver crude oil to a number of third-party refineries.
Retail marketing. Retail marketing business consists of the retail sale of gasoline and middle distillates and the operation of convenience stores.
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 segment are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability.
We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.
In marketing natural gas, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.
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 Product
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.

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

Our subsidiaries maintain credit policies with regard to our counterparties that we believe significantly reduce overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), requirements for collateral under certain circumstances, and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single or multiple counterparties.

Our subsidiaries' counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream, and power generation companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Currently, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty non-performance.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas have been negatively impacted in recent years by economic conditions and the discovery and development of new shale formations. As a result, many of our customers have been negatively impacted. We are diligent in attempting to mitigate credit risk relating to our customers.

During the year ended December 31, 2012, no individual customer accounted for more than 10% of our consolidated revenues.

Regulation

Regulation of Interstate Natural Gas Pipelines. FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the Natural Gas Act ("NGA"), 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 FERC's regulatory jurisdiction. ETP also holds certain storage facilities that are subject to the FERC's regulatory oversight. Additionally, Regency owns an indirect 50% interest in the entity that owns and operates the Midcontinent Express pipeline subject to the FERC's broad regulatory oversight.

The FERC's NGA authority includes, among other things, the power to regulate:

- the certification and construction of new facilities;
- the review and approval of transportation rates;
- the types of services that ETP's and Regency's 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

Table of Contents

• the initiation and discontinuation of services.

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

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

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

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

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, FERC determined that there was no reason at that time to expend FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided by the Company to FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. However, since 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, a rate proceeding could be initiated at that time and result in significant revenue reductions if the cost of service remains lower than revenues.

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. ETP and Regency 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.

Pursuant to the FERC’s rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (1) to defraud using any device, scheme or artifice; (2) to make any untrue statement of material fact or omit a material fact; or (3) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("CEA"). With regard to ETP's and Regency's physical purchases and sales of natural gas, NGLs or other energy commodities; their gathering or transportation of these energy commodities; and any related hedging activities that they undertake, ETP and Regency are required to observe these anti-market manipulation laws and related regulations enforced by 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 ETP or Regency violate the anti-market manipulation laws and regulations, they could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Table of Contents

Failure to comply with the NGA, the Energy Policy Act of 2005 and the other federal laws and regulations governing ETP's and Regency's 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 ETP's or Regency's intrastate natural gas transportation systems transport natural gas in interstate commerce, the rates and terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates and terms and conditions of some transportation and storage services provided on the Oasis pipeline, HPL System, East Texas pipeline and ET Fuel System are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than ETP's or Regency's currently approved Section 311 rates, ETP's or Regency's business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC approved statement of operating conditions could result in an alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

The FERC has adopted market-monitoring and annual reporting regulations, which regulations are applicable to many intrastate pipelines as well as other entities that are otherwise not subject to the FERC's NGA jurisdiction such as natural gas marketers. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve FERC's ability to assess market forces and detect market manipulation. The FERC has also issued regulations requiring interstate pipelines and certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information. As these posting requirements for major non-interstate pipelines have been vacated on appeal by the U.S. 5th Circuit Court of Appeals, it is not known with certainty whether and to what extent the FERC will continue to attempt to impose such posting requirements. Should the FERC succeed in reimposing these or similar regulations we could be subject to further costs and administrative burdens, none of which are expected to have a material impact on its operations.

Intrastate natural gas operations in Texas are also subject to regulation by various agencies in Texas, principally the Texas Railroad Commission ("TRRC"). ETP's 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 are not discriminatory. The rates charged 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 our subsidiaries 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.

Regency's RIGS system is subject to regulation by various agencies of the State of Louisiana. 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, it has not acted to exercise this jurisdiction respecting gathering facilities. Louisiana also has agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Regulation of Sales of Natural Gas and NGLs. The price at which ETP and Regency 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 ETP and Regency sell NGLs is not subject to federal or state regulation.

To the extent that ETP and Regency enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, they are subject to FERC requirements related to use of such capacity. Any failure on ETP's or Regency's 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.

ETP's and Regency's 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. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. ETP and Regency cannot predict the ultimate impact of these regulatory changes to its natural gas

Table of Contents

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. ETP and Regency do not believe that they will be affected by any such FERC action in a manner that is materially different from other natural gas marketers with whom they compete.

Regulation of Gathering Pipeline. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. ETP owns a number of natural gas pipelines in Texas, Louisiana, Colorado, West Virginia and Utah that it believes meet the traditional tests the FERC has used 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 ETP's gathering facilities could be subject to change based on future determinations by the FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In Texas, ETP's and Regency's gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for their 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, ETP's Chalkley System is regulated as an intrastate transporter, and the Louisiana Office of Conservation has determined that its Whiskey Bay System is a gathering system.

ETP and Regency are subject to state ratable take and common purchaser statutes in all of the states in which they 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. ETP's and Regency's 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. ETP's and Regency's 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. ETP and Regency cannot predict what effect, if any, such changes might have on their 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 FERC under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory. This statute also permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. 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.

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, 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.

Table of Contents

We have been approved by 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 Texas R.R.C., the P A PUC, and the OCC. 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. ETP's and Regency's pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT"), under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. In addition, the states in which ETP and Regency conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), which requires compliance with safety standards during construction and operation of certain pipelines and subjects the pipelines to regular inspections. Failure to comply with the safety laws and regulations may result in the imposition of administrative, civil and criminal remedies. The "rural gathering exemption" under the NGPSA presently exempts substantial portions of ETP's and Regency's gathering facilities from jurisdiction under the NGPSA, but does not apply to intrastate natural gas pipelines. The portions of ETP's and Regency's facilities that are exempt include those portions located outside of cities, towns or any area designated as residential or commercial, such as a subdivision or shopping center. Changes to federal pipeline safety laws and regulations are being considered by Congress and the DOT including changes to the "rural gathering exemption," which may be restricted in the future. Other safety regulations may be made more stringent and penalties could be increased. Such legislative and regulatory changes could have a material effect on ETP's and Regency's operations and costs of transportation service.

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

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, there can be no assurance that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the

operations, will not result in substantial costs and liabilities. We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.
Our subsidiaries have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage and to limit the financial liability which could result from such events. However, the risk of environmental or other damage is inherent in transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses. Environmental exposures and

Table of Contents

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 subsidiaries' liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future.

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 CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require some of our subsidiaries 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 a direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule is required by October 2013.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require some of our subsidiaries to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if equipment is replaced or existing facilities are expanded 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 our subsidiaries might make in the future, but 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.

On April 17, 2012 the EPA issued the Oil and Natural Gas Sector New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. The standards revise the new source performance standards for volatile organic compounds from leaking components at onshore natural gas processing plants and new source performance standards for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by the existing standards. In addition to the operations covered by the existing standards, the newly established standards regulate volatile organic compound emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels. ETP is reviewing the new standards to determine the impact on its operations.

Our subsidiaries' pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause our subsidiaries to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

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 MGPs and may also be responsible for the removal of old MGP structures.

Table of Contents

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 total accrued future estimated cost of remediation activities relating to ETP’s Transwestern pipeline operations was approximately $6 million as of December 31, 2012, which is included in the aggregate environmental accruals, and such activities are expected to continue through 2025.

The table below reflects the amounts (in millions) 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, 2012	December 31, 2011
Current	$46	$4
Non-current	166	10
Total environmental liabilities	$212	$14

Employees

As of January 31, 2013, ETE and its consolidated subsidiaries employed an aggregate of 14,433 employees, 2,067 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.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. In addition, those risk factors discussed in ETP's, Southern Union's and Sunoco Logistics' Annual Report on Form 10-K should be considered. The risk factors below, and those included in ETP's, Southern Union's and Sunoco Logistics' Annual Report, are not all the risks we face and other factors currently considered immaterial or unknown to us may impact or future operations.

These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Table of Contents

Risks Inherent in an Investment in Us

Our only significant assets are our partnership interests, including the incentive distribution rights, in ETP and Regency and, therefore, our cash flow is dependent upon the ability of ETP and Regency to make distributions in respect of those partnership interests.

We do not have any significant assets other than our partnership interests in ETP and Regency. As a result, our cash flow depends on the performance of ETP, Regency and their respective subsidiaries and ETP's and Regency's ability to make cash distributions to us, which is dependent on the results of operations, cash flows and financial condition of ETP and Regency.

The amount of cash that ETP and Regency can distribute to their partners, including us, each quarter depends upon the amount of cash they generate from their operations, which will fluctuate from quarter to quarter and will depend on, among other things:

- the amount of natural gas, crude oil and refined products transported through ETP's and Regency's transportation pipelines and gathering systems;
- the level of throughput in its processing and treating operations;
- the fees they charged and the margins realized by ETP and Regency for their services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the amount of cash distributions ETP receives with respect to its ownership of AmeriGas common units;
- the weather in their respective operating areas;
- the level of competition from other midstream, transportation and storage and retail marketing companies and other energy providers;
- the level of their respective operating costs;
- prevailing economic conditions; and
- the level and results of their respective derivative activities.

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

- the level of capital expenditures they make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- debt service requirements;
- fluctuations in working capital needs;
- their ability to borrow under their respective revolving credit facilities;
- their ability to access capital markets;
- restrictions on distributions contained in their respective debt agreements; and
- the amount, if any, of cash reserves established by the board of directors and their respective general partners in their discretion for the proper conduct of their respective businesses.

ETE does not have any control over many of these factors, including the level of cash reserves established by the board of directors and ETP's and Regency's respective General Partners. Accordingly, we cannot guarantee that ETP or Regency will have sufficient available cash to pay a specific level of cash distributions to its partners.

Furthermore, Unitholders should be aware that the amount of cash that ETP and Regency have available for distribution depends primarily upon cash flow and is not solely a function of profitability, which is affected by non-cash items. As a result, ETP and Regency may declare and/or pay cash distributions during periods when they record net losses. Please read "Risks Related to the Businesses of Energy Transfer Partners and Regency Energy Partners" included in this Item 1A for a discussion of further risks affecting ETP's and Regency's ability to generate distributable cash flow.

Cash distributions are not guaranteed and may fluctuate with our performance or other external factors.

The source of our earnings and cash flow is cash distributions from ETP and Regency. Therefore, the amount of distributions we are currently able to make to our Unitholders may fluctuate based on the level of distributions ETP and Regency makes to their partners. ETP or Regency may not be able to continue to make quarterly distributions at their current level or increase their quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our Unitholders if ETP or Regency increases or decreases distributions to us, the timing and amount of such increased or decreased distributions, if any, will not necessarily be comparable to the timing and amount of the increase or decrease in distributions made by ETP or Regency to us.

Our ability to distribute cash received from ETP and Regency to our Unitholders is limited by a number of factors, including:

- interest expense and principal payments on our indebtedness;
- restrictions on distributions contained in any current or future debt agreements;
- our general and administrative expenses;
- expenses of our subsidiaries other than ETP or Regency, including tax liabilities of our corporate subsidiaries, if any;
- capital contributions we may make to maintain our General Partner interests in ETP or Regency upon the issuance of additional partnership securities by ETP or Regency, as applicable; and
- reserves our General Partner believes prudent for us to maintain for the proper conduct of our business or to provide for future distributions.

We cannot guarantee that in the future we will be able to pay distributions or that any distributions we do make will be at or above our current quarterly distribution. The actual amount of cash that is available for distribution to our Unitholders will depend on numerous factors, many of which are beyond our control or the control of our General Partner.

The General Partner is not elected by the Unitholders and cannot be removed without its consent.

Unlike the holders of common stock in a corporation, our Unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our Unitholders do not have the ability to elect our General Partner or the officers or directors of our General Partner. Furthermore, if our Unitholders are dissatisfied with the performance of our General Partner, they may be unable to remove our General Partner. Our General Partner may not be removed except upon the vote of the holders of at least 66 $^{2}/3$% of our outstanding units. Our directors and executive officers directly or indirectly own 69,547,567 Common Units, representing approximately 19% of our outstanding Common Units. It will be particularly difficult for our General Partner to be removed without the consent of our directors and executive officers. As a result, the price at which our Common Units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

A reduction in ETP's or Regency's distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Our indirect ownership of 100% of the incentive distribution rights in ETP, through our ownership of equity interests in ETP GP, the holder of the incentive distribution rights, entitles us to receive our pro rata share of specified percentages of total cash distributions made by ETP as it reaches established target cash distribution levels. We currently receive our pro rata share of cash distributions from ETP based on the highest incremental percentage, 48%, to which ETP GP is entitled pursuant to its incentive distribution rights in ETP. A decrease in the amount of distributions by ETP to less than $0.4125 per Common Unit per quarter would reduce ETP GP's percentage of the incremental cash distributions above $0.3175 per Common Unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from ETP would have the effect of disproportionately reducing the amount of all distributions that we receive from ETP based on our ownership interest in the incentive distribution rights in ETP as compared to cash distributions we receive from ETP on our General Partner interest in ETP and our ETP Common Units.

Similarly, we receive a pro rata share of incremental cash distributions from Regency at the 23% level pursuant to Regency GP's incentive distribution rights in Regency. A decrease in the amount of distributions by Regency to less than $0.4375 per Common Unit per quarter would have reduced Regency GP's percentage of the incremental cash distributions above $0.4025 per Common Unit per quarter from 23% to 13%. As a result, any such reduction in quarterly cash distributions from Regency would have the effect of disproportionately reducing the amount of all distributions that we receive from Regency based on our ownership interest in the incentive distribution rights of Regency as compared to cash distributions we receive from Regency on our General Partner interest in Regency and our Regency Common Units.

The consolidated debt level and debt agreements of ETP and Regency and those of their subsidiaries may limit the distributions we receive from ETP and Regency, as well as our future financial and operating flexibility.

ETP's and Regency's levels of indebtedness affect their operations in several ways, including, among other things:

- a significant portion of ETP's, Regency's and their subsidiaries' cash flows from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions to us;
- covenants contained in ETP's, Regency's and their subsidiaries' existing debt agreements require ETP, Regency and their subsidiaries', as applicable, to meet financial tests that may adversely affect their flexibility in planning for and reacting to changes in their respective businesses;
- ETP's, Regency's and their subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership, corporate or limited liability company purposes, as applicable, may be limited;
- ETP and Regency may be at a competitive disadvantage relative to similar companies that have less debt;
- ETP and Regency may be more vulnerable to adverse economic and industry conditions as a result of their significant debt levels; and
- failure by ETP, Regency or their subsidiaries to comply with the various restrictive covenants of the respective debt agreements could negatively impact ETP's and Regency's ability to incur additional debt, including their ability to utilize the available capacity under their revolving credit facilities, and to pay distributions.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We cannot assure Unitholders that we will maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay capital expenditures, sell assets or operations, seek additional capital or restructure or refinance our indebtedness. We cannot assure Unitholders that we would be able to take any of these actions, that these actions would be successful and permit us to meet our scheduled debt service obligations or that these actions would be permitted under the terms of our existing or future debt agreements. In the absence of such cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our credit facilities restrict our ability to dispose of assets and use the proceeds from the disposition. We may not be able to consummate those dispositions or to obtain the proceeds that we could realize from them, and any proceeds may not be adequate to meet any debt service obligations then due.

ETP and Regency are not prohibited from competing with us.

Neither our partnership agreement nor the partnership agreements of ETP or Regency prohibit ETP or Regency from owning assets or engaging in businesses that compete directly or indirectly with us. Additionally, ETP's partnership agreement prohibits us from engaging in the retail propane business in the United States. In addition, ETP and/or Regency may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

Capital projects will require significant amounts of debt and equity financing which may not be available to ETP or Regency on acceptable terms, or at all.

ETP and Regency plan to fund their growth capital expenditures, including any new future pipeline construction projects and improvements or repairs to existing facilities that ETP or Regency may undertake, with proceeds from sales of ETP's or Regency's debt and equity securities and borrowings under their respective revolving credit facilities; however, ETP or Regency cannot be certain that they will be able to issue debt and equity securities on terms satisfactory to them, or at all. In addition, ETP or Regency may be unable to obtain adequate funding under their current revolving credit facility because ETP's or Regency's lending counterparties may be unwilling or unable to meet their funding obligations. If ETP or Regency are unable to finance their expansion projects as expected, ETP or

Regency could be required to seek alternative financing, the terms of which may not be attractive to ETP or Regency, or to revise or cancel its expansion plans.

A significant increase in ETP's or Regency's indebtedness that is proportionately greater than ETP's or Regency's respective issuances of equity could negatively impact ETP's or Regency's respective credit ratings or their ability to remain in compliance

Table of Contents

with the financial covenants under their respective revolving credit agreements, which could have a material adverse effect on ETP's or Regency's financial condition, results of operations and cash flows.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to changes in interest rates. To the extent that we have debt with floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner or indirect owners of our General Partner may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our General Partner and indirect owners over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from us to service their indebtedness.

We may issue an unlimited number of limited partner interests without the consent of our Unitholders, which will dilute Unitholders' ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

Our partnership agreement allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities by us will have the following effects:

- our Unitholders' current proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each Common Unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding Common Unit may be diminished; and
- the market price of our Common Units may decline.

In addition, ETP and Regency may sell an unlimited number of limited partner interests without the consent of the respective Unitholders, which will dilute existing interests of the respective Unitholders, including us. The issuance of additional Common Units or other equity securities by ETP will have essentially the same effects as detailed above.

The market price of our Common Units could be adversely affected by sales of substantial amounts of our units in the public markets, including sales by our existing Unitholders.

Sales by any of our existing Unitholders of a substantial number of our units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

Control of our General Partner may be transferred to a third party without Unitholder consent.

Our General Partner may transfer its general partner interest in us to a third party without the consent of our Unitholders. Furthermore, the members of our General Partner may transfer all or part of their ownership interest in our General Partner to a third party without the consent of the Unitholders. The new owner or owners of our General Partner or the general partner of the General Partner would then be in a position to replace the directors and officers of our General Partner and control the decisions made and actions taken by the board of directors and officers.

Table of Contents

Our General Partner has only one executive officer, and we are dependent on third parties, including key personnel of ETP under a shared services agreement, to provide the financial, accounting, administrative and legal services necessary to operate our business.

John W. McReynolds, the President and Chief Financial Officer of our General Partner, is the only executive officer charged with managing our business other than through our shared services agreement with ETP. We do not currently have a plan for identifying a successor to Mr. McReynolds in the event that he retires, dies or becomes disabled. If Mr. McReynolds ceases to serve as the President and Chief Financial Officer of our General Partner for any reason, we would be without executive management other than through our shared services agreement with ETP until one or more new executive officers are selected by the board of directors of our General Partner. As a consequence, the loss of Mr. McReynolds' services could have a material negative impact on the management of our business.

Moreover, we rely on the services of key personnel of ETP, including the ongoing involvement and continued leadership of Kelcy L. Warren, one of the founders of ETP's midstream business, as well as other key members of ETP's management team such as Marshall S. (Mackie) McCrea, III, President and Chief Operating Officer.

Mr. Warren has been integral to the success of ETP's midstream and intrastate transportation and storage businesses because of his ability to identify and develop strategic business opportunities. Losing his leadership could make it difficult for ETP to identify internal growth projects and accretive acquisitions, which could have a material adverse effect on ETP's ability to increase the cash distributions paid on its partnership interests.

ETP's executive officers that provide services to us pursuant to a shared services agreement allocate their time between us and ETP. To the extent that these officers face conflicts regarding the allocation of their time, we may not receive the level of attention from them that the management of our business requires. If ETP is unable to provide us with a sufficient number of personnel with the appropriate level of technical accounting and financial expertise, our internal accounting controls could be adversely impacted.

An increase in interest rates may cause the market price of our units to decline.

Like all equity investments, an investment in our units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our units to decline.

Limited partner's liability may not be limited, and our Unitholders may have to repay distributions or make additional contributions to us under limited circumstances.

As a limited partner in a partnership organized under Delaware law, a limited partner could be held liable for our obligations to the same extent as a general partner if it participates in the "control" of our business. Our general partner generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to our General Partner. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions in which we do business. In some of the jurisdictions in which we do business, the applicable statutes do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. A limited partner could, however, be liable for any and all of our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a limited partner's right to act with other Unitholders to take other actions under our partnership agreement is found to constitute "control" of our business.

Under limited circumstances, our Unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, neither Energy Transfer Equity, ETP nor

Regency may make a distribution to its Unitholders if the distribution would cause Energy Transfer Equity's, ETP's or Regency's respective liabilities to exceed the fair value of their respective assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, partners who received the distribution and knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Table of Contents

If we cease to manage and control ETP or Regency in the future, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control ETP or Regency and are deemed to be an investment company under the Investment Company Act of 1940 (the "Investment Company Act") we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the Securities and Exchange Commission or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. For further discussion of the importance of our treatment as a partnership for federal income tax purposes and the implications that would result from our treatment as a corporation in any taxable year, please read the risk factor below entitled "Our tax treatment depends on our continuing status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us, ETP or Regency as a corporation for federal income tax purposes or if we, ETP or Regency become subject to a material amount of additional entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to Unitholders.

If ETP GP or Regency GP withdraws or is removed as ETP's or Regency's General Partner, as applicable, then we would lose control over the management and affairs of ETP or Regency, the risk that we would be deemed an investment company under the Investment Company Act of 1940 would be exacerbated and our indirect ownership of the General Partner interests and 100% of the incentive distribution rights in ETP or Regency could be cashed out or converted into ETP or Regency Common Units, as applicable, at an unattractive valuation.

Under the terms of ETP's or Regency's respective partnership agreements, ETP GP or Regency GP, as applicable, will be deemed to have withdrawn as General Partner if, among other things, it:

- voluntarily withdraws from the partnership by giving notice to the other partners;
- transfers all, but not less than all, of its partnership interests to another entity in accordance with the terms of ETP's or Regency's partnership agreement, as applicable;
- makes a general assignment for the benefit of creditors, files a voluntary bankruptcy petition, seeks to liquidate, acquiesces in the appointment of a trustee, receiver or liquidator, or becomes subject to an involuntary bankruptcy petition; or
- dissolves itself under Delaware law without reinstatement within the requisite period.

In addition, ETP GP and Regency GP can be removed as ETP's or Regency's General Partner if that removal is approved by Unitholders holding at least 66 2/3% of ETP's or Regency's respective outstanding Common Units (including units held by ETP GP or Regency GP and their respective affiliates). Currently, ETP GP and its affiliates own approximately 17% of ETP's outstanding Common Units, and Regency GP and its affiliates own approximately 15% of Regency's outstanding Common Units.

If ETP GP or Regency GP withdraws from being ETP's or Regency's respective General Partner in compliance with ETP's or Regency's partnership agreement, as applicable, or is removed from being ETP's or Regency's respective General Partner under circumstances not involving a final adjudication of actual fraud, gross negligence or willful and wanton misconduct, it may require the successor General Partner to purchase its General Partner interests, incentive distribution rights and limited partner interests in ETP or Regency, as applicable, for fair market value. If ETP GP or Regency GP withdraws from being ETP's or Regency's respective General Partner in violation of ETP's or Regency's partnership agreement, as applicable, or is removed from being ETP's or Regency's General Partner in circumstances where a court enters a judgment that cannot be appealed finding it liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as ETP's or Regency's General Partner, and the successor General Partner does not exercise its option to purchase the General Partner interests, incentive distribution rights and limited partner interests in ETP or Regency, as applicable, for fair market value, then the General Partner interests and incentive distribution rights in ETP or Regency, as applicable, could be converted into limited partner interests pursuant to a valuation performed by an investment banking firm or other independent expert. Under any of the foregoing scenarios, ETP GP or Regency GP would lose control over the management and affairs of ETP or Regency, as applicable, thereby increasing the risk that we would be deemed an investment company subject to regulation under the Investment Company Act of 1940. In addition, our indirect ownership of the General Partner interests and 100% of the incentive distribution rights in ETP and Regency, to which a significant portion of the value of our Common Units is currently attributable, could be cashed out or converted into ETP or Regency Common Units, as applicable, at an unattractive valuation.

Table of Contents

Our partnership agreement restricts the rights of Unitholders owning 20% or more of our units.

Our Unitholders' voting rights are restricted by the provision in our partnership agreement generally providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our Unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our Unitholders' ability to influence the manner or direction of our management. As a result, the price at which our Common Units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Future sales of the ETP or Regency Common Units we own or other limited partner interests in the public market could reduce the market price of our Unitholders' limited partner interests.

As of December 31, 2012, we owned approximately 50.2 million Common Units of ETP and approximately 26.3 million Common Units of Regency. If we were to sell and/or distribute our ETP or Regency Common Units to the holders of our equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of ETP's or Regency's outstanding Common Units and our receipt of cash distributions.

Cost reimbursements due to our General Partner may be substantial and may reduce our ability to pay the distributions to our Unitholders.

Prior to making any distributions to our Unitholders, we will reimburse our General Partner for all expenses it has incurred on our behalf. In addition, our General Partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by our General Partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to our Unitholders. Our General Partner has sole discretion to determine the amount of these expenses and fees.

In addition, under Delaware partnership law, our General Partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our General Partner. To the extent our General Partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our General Partner, our General Partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash available for distribution to our Unitholders and cause the value of our Common Units to decline.

ETP or Regency may issue additional Common Units, which may increase the risk that ETP or Regency will not have sufficient available cash to maintain or increase its per unit distribution level.

The partnership agreements of each ETP and Regency allow ETP and Regency, respectively, to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by ETP or Regency will have the following effects:

- Unitholders' current proportionate ownership interest in ETP or Regency, as applicable, will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of ETP's or Regency's Common Units, as applicable, may decline.

The payment of distributions on any additional units issued by ETP or Regency may increase the risk that ETP or Regency, as applicable, may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.

Risks Related to Conflicts of Interest

Although we control ETP and Regency through our ownership of their respective General Partners, ETP's General Partner owes fiduciary duties to ETP and ETP's Unitholders, and Regency's General Partner owes fiduciary duties to Regency and Regency's Unitholders, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and ETP, Regency and their respective limited partners, on the other hand. The directors and officers of ETP's and Regency's General Partners have fiduciary duties to manage ETP and Regency, respectively, in a manner beneficial to us. At the same time,

Table of Contents

the General Partners have fiduciary duties to manage ETP and Regency, respectively, in a manner beneficial to ETP, Regency and their respective limited partners. The board of directors of ETP's General Partner or Regency's general partner will resolve any such conflict and have broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with ETP or Regency may arise in the following situations:

- the allocation of shared overhead expenses to ETP, Regency and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and ETP or Regency, on the other hand;
- the determination of the amount of cash to be distributed to ETP's or Regency's partners and the amount of cash to be reserved for the future conduct of ETP's or Regency's business;
- the determination whether to make borrowings under ETP's or Regency's respective revolving credit facility to pay distributions to ETP's or Regency's partners, as applicable; and
- any decision we make in the future to engage in business activities independent of ETP or Regency.

The fiduciary duties of our General Partner's officers and directors may conflict with those of ETP's or Regency's respective General Partners.

Conflicts of interest may arise because of the relationships among ETP, Regency, their General Partners and us. Our General Partner's directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our Unitholders. Some of our General Partner's directors are also directors and officers of ETP's General Partner or Regency's General Partner, and have fiduciary duties to manage the respective businesses of ETP and Regency in a manner beneficial to ETP, Regency and their respective Unitholders. The resolution of these conflicts may not always be in our best interest or that of our Unitholders.

Affiliates of our General Partner are not prohibited from competing with us.

Our partnership agreement provides that our General Partner will be restricted from engaging in any business activities other than acting as our General Partner and those activities incidental to its ownership of interests in us. Except as provided in our partnership agreement, affiliates of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

Potential conflicts of interest may arise among our General Partner, its affiliates and us. Our General Partner and its affiliates have limited fiduciary duties to us, which may permit them to favor their own interests to the detriment of us.

Conflicts of interest may arise among our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following:

- Our General Partner is allowed to take into account the interests of parties other than us, including ETP, Regency and their respective affiliates and any General Partners and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duties to us.
- Our General Partner has limited its liability and reduced its fiduciary duties under the terms of our partnership agreement, while also restricting the remedies available for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, Unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.
- Our General Partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution.
- Our General Partner determines which costs it and its affiliates have incurred are reimbursable by us.
- Our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- Our General Partner controls the enforcement of obligations owed to us by it and its affiliates.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Table of Contents

Our partnership agreement limits our General Partner's fiduciary duties to us and restricts the remedies available for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our General Partner is entitled to make other decisions in "good faith" if it reasonably believes that the decisions are in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Audit and Conflicts Committee of the board of directors of our General Partner and not involving a vote of Unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

Our General Partner has a limited call right that may require Unitholders to sell their units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 90% of our outstanding units, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, Unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2012, the directors and executive officers of our General Partner owned approximately 19% of our Common Units.

ETP and Regency own interstate pipelines that are subject to rate regulation by the Federal Energy Regulatory Commission and, in the event that 15% or more of our outstanding Common Units, in the aggregate, are held by persons who are not eligible holders, Common Units held by persons who are not eligible holders will be subject to the possibility of redemption at the then-current market price.

ETP and Regency own interstate pipelines that are subject to rate regulation of the Federal Energy Regulatory Commission, FERC, and as a result our General Partner has the right under our partnership agreement to institute procedures, by giving notice to each of our Unitholders, that would require transferees of Common Units and, upon the request of our General Partner, existing holders of our Common Units to certify that they are Eligible Holders. The purpose of these certification procedures would be to enable us to utilize a federal income tax expense as a component of the pipeline's rate base upon which tariffs may be established under FERC rate-making policies applicable to entities that pass-through their taxable income to their owners. Eligible Holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity's owners are subject to such taxation. If these tax certification procedures are implemented and 15% or more of our outstanding Common Units are held by persons who are not Eligible Holders, we will have the right to redeem the units held by persons who are not Eligible Holders at the then-current market price. The redemption price would be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Risks Related to the Businesses of ETP and Regency

Since our cash flows consist exclusively of distributions from ETP and Regency, risks to the businesses of ETP and Regency are also risks to us. We have set forth below risks to the businesses of ETP and Regency, the occurrence of which could have a negative impact on their respective financial performance and decrease the amount of cash they

are able to distribute to us.
ETP and Regency do not control, and therefore may not be able to cause or prevent certain actions by, certain of their joint ventures.
Certain of ETP's and Regency's joint ventures have their own governing boards, and ETP or Regency may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for ETP or Regency to cause the joint venture entity to

Table of Contents

take actions that ETP or Regency believe would be in their or the joint venture's best interests. Likewise, ETP or Regency may be unable to prevent actions of the joint venture.

ETP and Regency are exposed to the credit risk of their respective customers, and an increase in the nonpayment and nonperformance by their respective customers could reduce their respective ability to make distributions to their Unitholders, including to us.

The risks of nonpayment and nonperformance by ETP's and Regency's respective customers are a major concern in their respective businesses. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. ETP and Regency are subject to risks of loss resulting from nonpayment or nonperformance by their respective customers. The current tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by ETP's and Regency's customers. Any substantial increase in the nonpayment and nonperformance by ETP's or Regency's customers could have a material adverse effect on ETP's or Regency's respective results of operations and operating cash flows.

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

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

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

In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2012, the NYMEX natural gas settlement price for the prompt month contract ranged from a high of $3.70 per MMBtu to a low of $2.04 per MMBtu. A composite of the Mont Belvieu average NGLs price based upon our average NGLs composition during our year ended December 31, 2012 ranged from a high of approximately $1.23 per gallon to a low of approximately $0.75 per gallon. Oil spot prices at Cushing, Oklahoma during the year ended December 31, 2012 ranged from a high of approximately $109.39 per barrel to a low of approximately $77.72 per barrel.

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

We may be impacted by competition from other midstream, transportation and storage and retail marketing companies.

We experience competition in all of our business segments. With respect to our intrastate transportation and storage segment, our principal areas of competition include obtaining natural gas supplies for the Southeast Texas System, North Texas System and HPL System and natural gas transportation customers for our transportation pipeline systems. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas.

Our natural gas and NGL transportation pipelines and storage facilities compete with other interstate and intrastate pipeline companies and storage providers in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, access to sources of supply and the flexibility and reliability of service. Natural gas and NGLs

also competes with other forms of energy, including electricity, coal, fuel oils and renewable or alternative energy. Competition among fuels and energy supplies is primarily based on price; however, non-price factors, including governmental regulation, environmental impacts, efficiency, ease of use and handling, and the availability of subsidies and tax benefits also affects competitive outcomes.

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

Our crude oil and refined products pipeline operations face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in areas served by Sunoco Logistics' pipelines. Further, our refined product terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

We also face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations operated by fully integrated major oil companies and other well-recognized national or regional retail outlets, often selling gasoline or merchandise at aggressively competitive prices. The actions of our retail marketing competitors, including the impact of foreign imports, could lead to lower prices or reduced margins for the products we sell, which could have an adverse effect on our business or results of operations.

We may be unable to retain or replace existing midstream, transportation, terminalling and storage customers or volumes due to declining demand or increased competition in oil, natural gas and NGL markets, which would reduce our revenues and limit our future profitability.

The retention or replacement of existing customers and the volume of services that we provide at rates sufficient to maintain or increase current revenues and cash flows depends on a number of factors beyond our control, including the price of, and demand for oil, natural gas, and NGLs in the markets we serve and competition from other service providers.

A significant portion of our sales of natural gas are to industrial customers and utilities. As a consequence of the volatility of natural gas prices and increased competition in the industry and other factors, industrial customers, utilities and other gas customers are increasingly reluctant to enter into long-term purchase contracts. Many customers purchase natural gas from more than one supplier and have the ability to change suppliers at any time. Some of these customers also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in natural gas sales markets primarily on the basis of price.

We also receive a substantial portion of our revenues by providing natural gas gathering, processing, treating, transportation and storage services. While a substantial portion of our services are sold under long-term contracts for reserved service, we also provide service on an unreserved or short-term basis. Demand for our services may be substantially reduced due to changing market prices. Declining prices may result in lower rates of natural gas production resulting in less use of services; while rising prices may diminish consumer demand and also limit the use of services. In addition, our competitors may attract our customers' business. If demand declines or the effects of competition increases, we may not be able to sustain existing levels of unreserved service or renew or extend long-term contracts as they expire or we may reduce our rates to meet competitive pressures.

Revenue from our NGL transportation systems and refined products storage is also exposed to risks due to fluctuations in demand for transportation and storage service as a result of unfavorable commodity prices, competition from nearby pipelines, and other factors. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. Reduction in demand for natural gas or NGLs due to unfavorable prices or other factors, however, may result lower rates of production under dedicated contracts and lower demand for our services. In addition, our refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, a portion of our revenue is derived from fungible storage and throughput arrangements, under which our revenue is more dependent upon demand for storage from our customers.

The volume of crude oil and refined products transported through our oil pipelines and terminal facilities depends on the availability of attractively priced crude oil and refined products in the areas serviced by our assets. A period of sustained price reductions for crude oil or refined products could lead to a decline in drilling activity, production and refining of crude oil, or import levels in these areas. A period of sustained increases in the price of crude oil or refined products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined products in these areas. In either case, the volumes of crude oil or refined products transported in our oil pipelines and terminal facilities could decline.

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

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

In order to maintain or increase throughput levels on our gathering systems and transportation pipeline systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies and natural gas transportation services.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. Our gas transportation pipelines are also dependent upon natural gas production in areas served by our gathering systems or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. We may not be able to obtain additional contracts for natural gas supplies for our natural gas gathering systems, and we may be unable to maintain or increase the levels of natural gas throughput on our transportation pipelines. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity and production of natural gas near our gathering systems or in areas that provide access to our transportation pipelines or markets to which our systems connect. We have no control over the level of drilling activity in our areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, we have no control over producers or their production and contracting decisions.

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

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

As a result of our exit from the refining business, we are entirely dependent upon third parties for the supply of refined products such as gasoline and diesel for our retail marketing business.

As a result of our exit from the refining business, we are required to purchase refined products from third party sources, including the joint venture that acquired our Philadelphia refinery. We may also need to contract for new ships, barges, pipelines or terminals which we have not historically used to transport these products to our markets. The inability to acquire refined products and any required transportation services at prices no less favorable than the formerly applicable market-based transfer prices may adversely affect our business and results of operations.

The profitability of certain activities in our natural gas gathering, processing, transportation and storage operations are largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs.

For a portion of the natural gas gathered at our systems, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices.

We also enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers.

Under percent-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements, our revenues and gross

margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our revenues and results of operations.
Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of

Table of Contents

the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs if we are not able to bypass our processing plants and sell the unprocessed natural gas.

When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. If recoveries are less than those guaranteed to the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole.

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

In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

The use of derivative financial instruments could result in material financial losses by ETP and Regency.

From time to time, ETP and Regency have sought to reduce our exposure to fluctuations in commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by their trading, marketing and/or system optimization activities. To the extent that either ETP or Regency hedges its commodity price and interest rate exposures, it foregoes the benefits it would otherwise experience if commodity prices or interest rates were to change favorably. In addition, even though monitored by management, ETP’s and Regency’s derivatives activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to ETP’s or Regency’s physical or financial positions, or internal hedging policies and procedures are not followed.

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

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

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

Our natural gas transportation, storage and NGL businesses depend, in part, on our customers' ability to obtain access to pipelines to deliver gas to us and receive gas from us. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on our pipelines or third party pipelines due to testing, line repair, reduced operating pressures, or other causes or adverse change in terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our pipelines and facilities and a corresponding material adverse effect on our transportation and storage revenues. In addition, the rates charged by interconnected pipelines for transportation to and from our facilities affect the utilization and value of our storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues Shippers using our oil pipelines and terminals are also dependent upon our pipelines and connections to third-party pipelines to receive and deliver crude oil and refined products. Any interruptions or reduction in the capabilities of these pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volume over interconnecting oil pipelines, the allocations of pipeline capacity to our existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in its pipelines or through our terminals. Allocation reductions of this nature are not infrequent and are beyond our control. Any such interruptions or allocation reductions that, individually or in the aggregate, are material or continue for a sustained period of time could have a material adverse effect on our results of operations, financial position, or cash flows.

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

Our ability to operate our pipeline systems and terminal facilities on certain lands owned by third parties, including lands held in trust by the United States for the benefit of a Native American tribe, will depend on our success in maintaining existing rights-of-way and obtaining new rights-of-way on those lands. Securing extensions of existing and any additional rights-of-way is also critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to acquire new rights-of-way or maintain access to existing rights-of-way upon the expiration of the current grants or that all of the rights-of-way will be obtainable in a timely fashion. Transwestern's existing right-of-way agreements with the Navajo Nation, Southern Ute, Pueblo of Laguna and Fort Mojave tribes extend through November 2029, September 2020, December 2022 and April 2019, respectively. Our financial position could be adversely affected if the costs of new or extended right-of-way grants cannot be recovered in rates.

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

ETP and Regency may not be able to fully execute their growth strategies if they encounter increased competition for qualified assets.

ETP and Regency each have strategies that contemplate growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining strong balance sheets. These strategies include constructing and acquiring additional assets and businesses to enhance their ability to compete effectively and diversify their respective asset portfolios, thereby providing more stable cash flow. ETP and Regency regularly consider and enter into discussions regarding the acquisition of additional assets and businesses, stand-alone development projects or other transactions that ETP and Regency believe will present opportunities to realize synergies and increase cash flow.

Consistent with their strategies, managements of ETP and Regency may, from time to time, engage in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve ETP or Regency management's participation in processes that involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which ETP or Regency believes it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot assure that ETP's or Regency's acquisition efforts will be successful or that any acquisition will be completed on favorable terms.

In addition, ETP and Regency each are experiencing increased competition for the assets they purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in ETP or Regency losing to other bidders more often or acquiring assets at higher prices, both of which would limit ETP's or Regency's ability to fully execute their respective growth strategies. Inability to execute their respective growth strategies may materially adversely impact ETP's or Regency's results of operations.

An impairment of goodwill and intangible assets could reduce our earnings.

As of December 31, 2012, our consolidated balance sheets reflected $6.43 billion of goodwill and $2.29 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

If ETP and Regency do not make acquisitions on economically acceptable terms, their future growth could be limited.

ETP's and Regency's results of operations and their ability to grow and to increase distributions to Unitholders will depend in part on their ability to make acquisitions that are accretive to their respective distributable cash flow.

ETP and Regency may be unable to make accretive acquisitions for any of the following reasons, among others:

- inability to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;

Table of Contents

- inability to raise financing for such acquisitions on economically acceptable terms; or
- inability to outbid by competitors, some of which are substantially larger than ETP or Regency and may have greater financial resources and lower costs of capital.

Furthermore, even if ETP or Regency consummates acquisitions that it believes will be accretive, those acquisitions may in fact adversely affect its results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that ETP or Regency may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease its liquidity by using a significant portion of its available cash or borrowing capacity to finance acquisitions;
- significantly increase its interest expense or financial leverage if the acquisition is financed with additional debt;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which there is no indemnity or the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate its growing business and assets;
- less effectively manage its historical assets, due to the diversion of management's attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

If ETP and Regency consummate future acquisitions, their respective capitalization and results of operations may change significantly. As ETP and Regency determine the application of their funds and other resources, Unitholders will not have an opportunity to evaluate the economics, financial and other relevant information that ETP and Regency will consider.

If ETP and Regency do not continue to construct new pipelines, their future growth could be limited.

During the past several years, ETP and Regency have constructed several new pipelines, and ETP and Regency are currently involved in constructing additional pipelines. ETP's and Regency's results of operations and their ability to grow and to increase distributable cash flow per unit will depend, in part, on their ability to construct pipelines that are accretive to their respective distributable cash flow. ETP or Regency may be unable to construct pipelines that are accretive to distributable cash flow for any of the following reasons, among others:

- inability to identify pipeline construction opportunities with favorable projected financial returns;
- inability to raise financing for its identified pipeline construction opportunities; or
- inability to secure sufficient transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if ETP or Regency constructs a pipeline that it believes will be accretive, the pipeline may in fact adversely affect its results of operations or fail to achieve results projected prior to commencement of construction.

Expanding ETP's and Regency's business by constructing new pipelines and related facilities subjects ETP and Regency to risks.

One of the ways that ETP and Regency have grown their respective businesses is through the construction of additions to existing gathering, compression, treating, processing and transportation systems. The construction of a new pipeline and related facilities (or the improvement and repair of existing facilities) involves numerous regulatory, environmental, political and legal uncertainties beyond ETP's and Regency's control and require the expenditure of significant amounts of capital to be financed through borrowings, the issuance of additional equity or from operating cash flow. If ETP or Regency undertakes these projects, they may not be completed on schedule or at all or at the budgeted cost. A variety of factors outside ETP's or Regency's control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third-party contractors may result in increased costs or delays in construction. Cost overruns or delays in completing a project could have a material adverse effect on ETP's or Regency's results of operations and cash flows. Moreover, revenues may not increase immediately following the completion of a particular project. For instance, if ETP or Regency builds a new pipeline, the construction will occur over an extended period of time, but ETP or Regency, as applicable, may not materially increase its revenues until long after the project's completion. In addition, the success of a pipeline construction project will likely depend upon the level of oil and natural gas exploration and development drilling activity and the demand for pipeline transportation in the areas proposed to be serviced by the project as well as ETP's and Regency's abilities to obtain commitments from producers in the area to utilize the newly constructed pipelines. In this regard, ETP and Regency may construct facilities to capture anticipated future growth in oil or natural gas production in a region in which such growth does not materialize. As a result, new facilities may be unable to attract enough throughput or contracted capacity reservation commitments to achieve ETP's or Regency's expected investment return, which could adversely affect its results of operations and financial condition.

ETP and Regency depend on certain key producers for a significant portion of their supplies of natural gas. The loss of, or reduction in, any of these key producers could adversely affect ETP's or Regency's respective business and operating results.

ETP and Regency rely on a limited number of producers for a significant portion of their natural gas supplies. These contracts have terms that range from month-to-month to life of lease. As these contracts expire, ETP and Regency will have to negotiate extensions or renewals or replace the contracts with those of other suppliers. ETP and Regency may be unable to obtain new or renewed contracts on favorable terms, if at all. The loss of all or even a portion of the volumes of natural gas supplied by these producers and other customers, as a result of competition or otherwise, could have a material adverse effect on ETP's and Regency's business, results of operations, and financial condition.

ETP and Regency depend on key customers to transport natural gas through their pipelines.

ETP and Regency rely on a limited number of major shippers to transport certain minimum volumes of natural gas on their respective pipelines, and Regency maintains contracts for compression services with a limited number of key customers. The failure of the major shippers on ETP's, Regency's or their joint ventures' pipelines or of other key customers to fulfill their contractual obligations under these contracts could have a material adverse effect on the cash flow and results of operations of us, ETP, Regency or their joint ventures, as applicable, were unable to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

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

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

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

FERC may review existing tariffs rates own initiative or upon receipt of a complaint filed by a third party. FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. FERC has recently exercised this authority with respect to several other pipeline companies, as it had in 2007 with respect to our Southwest Gas. If FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates customers could elect to pay us may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

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

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

In 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, FERC determined that there was no reason at that time to expend FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided by the Company to FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. However, since 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,

Table of Contents

a rate proceeding could be initiated at that time and result in significant revenue reductions if the cost of service remains lower than revenues.

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

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before FERC and the courts for a number of years. It is currently FERC’s policy to permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline’s owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. Under FERC’s policy, we thus remain eligible to include an income tax allowance in the tariff rates we charge for interstate natural gas transportation. The effectiveness of FERC's policy and the application of that policy remains subject to future challenges, refinement or change by FERC or the courts. With regard to rates charged and collected by Transwestern, the allowance for income taxes as a cost-of-service element in our tariff rates is generally not subject to challenge prior to the end of the term of our 2011 rate case settlement.

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

In addition to rate oversight, FERC’s regulatory authority extends to many other aspects of the business and operations of ETP’s and Regency’s interstate pipelines, including:

- operating terms and conditions of service;
- the types of services interstate pipelines may or must offer their customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. Future changes to laws, regulations, policies and interpretations thereof in these areas may impair the ability of ETP’s and Regency’s interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

ETP and Regency must on occasion rely upon rulings by FERC or other governmental authorities to carry out certain of their business plans. For example, in order to carry out its plan to construct the Fayetteville Express and Tiger pipelines ETP was required to, among other things, file and support before FERC NGA Section 7(c) applications for certificates of public convenience and necessity to build, own and operate such facilities. ETP and Regency cannot guarantee that FERC will authorize construction and operation of any future interstate natural gas transportation project it might propose. ETP and Regency are required to attain approval from FERC for expansions of their pipeline facilities. ETP cannot guarantee that FERC will authorize any future interstate natural gas transportation project ETP might propose. Moreover, there is no guarantee that certificate authority for interstate projects will be granted in a timely manner or without being subject to potentially burdensome conditions. We may also begin to construct a new facility or provide a new service based on a FERC authorization that is subsequently overturned or modified after review by a court. This could have a material adverse effect on the costs of and revenues of the new facility or service Similarly, MEP was required to obtain from FERC a certificate of public convenience and necessity to build, own and operate the Midcontinent Express pipeline. Although the FERC has granted such certificate authority, the FERC’s certificate order is currently pending judicial review before the United States Court of Appeals for the District of Columbia Circuit. ETP and Regency cannot give any assurance that the court will affirm, in all material respects, the FERC’s July 25, 2008 Midcontinent Express certificate order, or that the FERC will not materially alter the certificate order on any remand that might be ordered by the court. There are also pending requests for rehearing related to certain of the FERC's post-certification orders related to the Midcontinent Express project. ETP and Regency cannot guarantee that these post-certification orders will not be altered on rehearing or that these orders will not be subject to judicial review.

Failure to comply with all applicable FERC-administered statutes, rules, regulations and orders, could bring substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation. FERC possesses similar authority under the NGPA.

Finally, we, ETP and Regency cannot give any assurance regarding the likely future regulations under which ETP or Regency will operate its interstate pipelines or the effect such regulation could have on its business, financial condition, and results of operations.

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

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

The primary ratemaking methodology used by FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. If the rate changes allowed under the indexing methodology are not large enough to fully reflect actual increases to our pipeline costs, our financial condition could be adversely affected. If applying the index methodology results in a rate increase that is substantially in excess of our pipeline's actual cost increases, or it results in a rate decrease that is substantially less than our pipeline's actual cost decrease, we may be required to reduce our pipeline rates. FERC's ratemaking methodologies may limit our ability to set rates based on its costs or may delay the use of rates that reflect increased costs. In addition, if FERC's indexing methodology changes, the new methodology could materially and adversely affect our financial condition, results of operations or cash flows.

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

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

Should we violate laws and regulations prohibiting market manipulation, we could be subject to substantial fines and penalties and lose the governmental authorizations needed conduct our businesses.

The Energy Policy Act of 2005 amended the NGA and NGPA to prohibit fraud and manipulation in natural gas markets. FERC subsequently issued a final rule making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC's jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud. FERC is authorized to impose civil penalties of up to $1 million per day per violation and grant other relief, such as ordering refunds, or revoking operating authority.

Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 (“EISA”) and regulations by the FTC. Under the EISA, the FTC issued a rule that prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. The FTC rule also bans intentional failures to state a material fact when the omission makes a statement misleading and distorts, or is likely to distort, market conditions for any product covered by the rule. The FTC holds substantial enforcement authority under the EISA, including authority to request that a court impose fines of up to $1 million per day per violation. FERC may also order reparations and suspend tariffs for

violations of the ICA in connection with interstate oil pipeline transportation.
Under the Commodity Exchange Act, the CFTC is directed to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to assess fines of up to $1,000,000 or triple the monetary gain for violations of its anti-market manipulation regulations.

State regulatory measures could adversely affect the business and operations of our midstream and intrastate pipeline and storage assets.

Our midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects our business and the market for our products. The rates, terms and conditions of service for the interstate services we provide in our intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. Our HPL System, East Texas pipeline, Oasis pipeline and ET Fuel System provide such services. Under Section 311, rates charged for transportation and storage must be fair and equitable. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline's statement of operating conditions, are subject to FERC review and approval. Should FERC determine not to authorize rates equal to or greater than our costs of service, our cash flow would be negatively affected.

Our midstream and intrastate gas and oil transportation pipelines and our intrastate gas storage operations are subject to state regulation. All of the states in which we operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted some form of complaint-based regulation, which allow producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to the fairness of rates and terms of access. The states in which we operate have ratable take statutes, which generally require gatherers to take, without undue discrimination, production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Should a complaint be filed in any of these states or should regulation become more active, our business may be adversely affected.

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

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

Certain of ETP’s and Regency’s assets may become subject to regulation.

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

We are subject to extensive federal and state pipeline safety regulation, including integrity management requirements, which may adversely affect our costs and operations.

Our pipeline operations are subject to regulation by the DOT, under PHMSA, pursuant to which PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements will result in capital costs of $3.4 million and operating and maintenance costs of $17.9 million over the course of the next year. For the years ended December 31, 2012, 2011 and 2010, $0.0 million, $18.3 million and $13.3 million, respectively, of capital costs and $0.0 million, $14.7 million and $15.4 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Federal pipeline safety regulation is also becoming increasingly stringent and additional laws and regulations are being considered. The recently enacted Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The law requires numerous studies and/or the development of rules over the next two years covering the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related rules. The DOT has already proposed rules that address many areas of the newly adopted legislation.

On August 13, 2012, PHMSA published rules to update pipeline safety regulations to reflect provisions included in the Pipeline Safety Act of 2011, including increasing maximum civil penalties and changing PHMSA's enforcement process. PHMSA has also published advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations for oil and gas pipelines, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines.

Further, additional laws, regulations and policies that may be enacted or adopted in the future or a new interpretation of existing laws and regulations could significantly increase the cost of complying with safety laws and regulations. For example, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs or result in reductions of allowable operating pressures, which would reduce available pipeline capacity. Such legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

States are largely preempted by federal law from regulating pipeline safety for interstate lines, but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens. We are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling points without the benefit of chilling or refrigeration are exempt.

Should we violate federal or state health and safety laws and regulations, we could be subject to substantial criminal, civil and administrative penalties and other relief, as well as potential liabilities to third parties.

Our natural gas distribution operations subject us to risks that could have a material adverse effect on our business, results of operations, cash flows and financial condition.

On December 17, 2012, Southern Union entered into definitive purchase and sale agreements with subsidiaries of the Laclede Group, Inc. to sell the assets of its Missouri Gas Energy and New England Gas Company Divisions. Until the transaction is consummated, we will be subject to various risks relating to our natural gas distribution operations, including the following:

- our ability to achieve timely and effective rate relief from state regulators;

- the impact of fluctuations in natural gas prices;
- the inability to recover from customers certain assets recorded on our balance sheet;
- adverse weather conditions;
- operational risks, including accidents, the breakdown or failure of equipment or processes, the failure of suppliers' processing facilities to perform at expected levels of capacity or efficiency and the collision of equipment with facilities; and

51

Table of Contents

- catastrophic events, including explosions, fires, earthquakes, floods, landslides, tornadoes, lightning or other similar events.

ETP's and Regency's businesses involve hazardous substances and may be adversely affected by environmental regulation.

ETP's and Regency's operations are subject to stringent federal, state and local laws and regulations that seek to protect human health and the environment, including those governing the emission or discharge of materials into the environment. These laws and regulations may require the acquisition of permits for ETP's and Regency's operations, result in capital expenditures to manage, limit, or prevent emissions, discharges or releases of various materials from ETP's and Regency's pipelines, plants and facilities and impose substantial liabilities for pollution resulting from ETP's and Regency's operations. Several governmental authorities, such as the EPA have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions. Failure to comply with these laws, regulations and permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctive relief.

ETP and Regency may incur substantial environmental costs and liabilities because of the underlying risk inherent to its operations. Certain environmental laws and regulations can provide for joint and several strict liability for cleanup to address discharges or releases of petroleum hydrocarbons or other materials or wastes at sites to which ETP or Regency may have sent wastes or on, under, or from ETP's and Regency's current or former properties and facilities, many of which have been used for industrial activities for a number of years, even if such discharges were caused by ETP's and Regency's respective predecessors. Private parties, including the owners of properties through which ETP's and Regency's pipelines or gathering systems pass or facilities where their petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation liabilities. Environmental laws also authorize government agencies, in some circumstance, to seek compensation for natural resource damages as an adjunct to remediation programs. If such natural resource damages claims are brought against us, our liability associated with any such sites could substantially increase. Accordingly, we cannot assure you that our current reserves are adequate to cover all future liabilities, even for currently known contamination.

Changes in environmental laws and regulations occur frequently, and changes that result in significantly more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on ETP's and Regency's operations or financial position. For example, the EPA in 2008 lowered the federal ozone standard from 0.08 ppm to 0.075 ppm, requiring the environmental agencies in states with areas that do not currently meet this standard to adopt new rules to further reduce NOx and other ozone precursor emissions. ETP and Regency have previously been able to satisfy the more stringent NOx emission reduction requirements that affect its compressor units in ozone non-attainment areas at reasonable cost, but there is no guarantee that the changes ETP or Regency may have to make in the future to meet the new ozone standard or other evolving standards will not require it to incur costs that could be material to its operations.

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

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

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

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

On April 17, 2012, the EPA issued final rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s proposed rule package includes New Source Performance Standards (”NSPS”) to address emissions of sulfur dioxide and volatile organic compounds (”VOCs”), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA’s proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing by January 2015, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. These rules will require us to modify certain of our operations, including the possible installation of new equipment. Compliance with such rules will be required within three years of their effective date, and it could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the natural gas, NGLs, crude oil and refined products that ETP and Regency transport, store or otherwise handle.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA has recently adopted rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and another which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. In November 2011, the EPA also adopted rules requiring companies with facilities that emit over 25,000 metric tons or more of carbon dioxide to report their greenhouse gas emissions to the EPA by September 30, 2012, a requirement with which we timely complied.

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

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require ETP or Regency to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, natural gas, NGLs, crude oil and refined products. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on ETP’s or Regency’s businesses, financial conditions and results of operations.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, the operations of ETP and Regency could be adversely affected in various ways, including damages to their 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 ETP’s and Regency’s fuel 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 ETP and Regency 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 ETP’s and Regency’s fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on the business of ETP and Regency.

The adoption of the Dodd -Frank Act could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business, resulting in our operations becoming more volatile and our cash flows less predictable.

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

Table of Contents

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

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

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

The new regulations may also require us to comply with certain margin requirements for our over-the counter derivative contracts with certain CFTC- or SEC-registered entities that could require us to enter into credit support documentation and/or post significant amounts of cash collateral, which could adversely affect our liquidity and ability to use derivatives to hedge our commercial price risk; however, the proposed margin rules are not yet final and therefore the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The new legislation also requires that certain derivative instruments be centrally cleared and executed through an exchange or other approved trading platform. Mandatory exchange trading and clearing requirements could result in increased costs in the form of additional margin requirements imposed by clearing organizations. On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although there may be an exception to the mandatory exchange trading and clearing requirement that applies to our trading activities, we must obtain approval from the board of directors of our General Partner and make certain filings in order to rely on this exception. In addition, mandatory clearing requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

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

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail ETP's and Regency's operations and otherwise materially adversely affect their cash flow.

Some of ETP's and Regency's operations involve risks of personal injury, property damage and environmental damage, which could curtail its operations and otherwise materially adversely affect its cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. Virtually all of ETP's and Regency's operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

If one or more facilities that are owned by ETP or Regency or that deliver natural gas or other products to ETP or Regency are damaged by severe weather or any other disaster, accident, catastrophe or event, ETP's or Regency's operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply ETP's or

Table of Contents

Regency's facilities or other stoppages arising from factors beyond its control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the revenues generated by ETP's or Regency's operations, or which causes it to make significant expenditures not covered by insurance, could reduce ETP's or Regency's cash available for paying distributions to its Unitholders, including us.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, ETP and Regency may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If ETP or Regency were to incur a significant liability for which it was not fully insured, it could have a material adverse effect on ETP's or Regency's financial position and results of operations, as applicable. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Terrorist attacks aimed at our facilities could adversely affect its business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including the nation's pipeline infrastructure, may be the future target of terrorist organizations. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such terrorist attack on ETP's or Regency's facilities or pipelines or those of its customers could have a material adverse effect on ETP's or Regency's business, as applicable.

ETP has a significant equity investment in AmeriGas and the value of this investment, and the cash distributions ETP expects to receive from this investment, are subject to the risks encountered by AmeriGas with respect to its business.

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

- adverse weather condition resulting in reduced demand;
- cost volatility and availability of propane, and the capacity to transport propane to its customers;
- the availability of, and its ability to consummate, acquisition or combination opportunities;
- successful integration and future performance of acquired assets or businesses;
- changes in laws and regulations, including safety, tax, consumer protection and accounting matters;
- competitive pressures from the same and alternative energy sources;
- failure to acquire new customers and retain current customers thereby reducing or limiting any increase in revenues;
- liability for environmental claims;
- increased customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand;
- adverse labor relations;
- large customer, counter-party or supplier defaults;
- liability in excess of insurance coverage for personal injury and property damage arising from explosions and other catastrophic events, including acts of terrorism, resulting from operating hazards and risks incidental to transporting, storing and distributing propane, butane and ammonia;
- political, regulatory and economic conditions in the United States and foreign countries;
- capital market conditions, including reduced access to capital markets and interest rate fluctuations;
- changes in commodity market prices resulting in significantly higher cash collateral requirements;
- the impact of pending and future legal proceedings;
- the timing and success of its acquisitions and investments to grow its business; and

Table of Contents

•its ability to successfully integrate acquired businesses and achieve anticipated synergies.

We are subject to risks resulting from the moratorium in 2010 on and the resulting increased costs of offshore deepwater drilling.

The United States Department of Interior (the “DOI”) implemented a six-month moratorium on offshore drilling in water deeper than 500 feet in response to the Macondo accident and oil spill in the U.S. Gulf of Mexico. The offshore drilling moratorium was implemented to permit the DOI to review the safety protocols and procedures used by offshore drilling companies, which review will enable the DOI to recommend enhanced safety and training needs for offshore drilling companies. The moratorium was lifted in October 2010. The United States Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement (formerly the Bureau of Ocean Energy Management, Regulation and Enforcement) have enacted enhanced regulatory mandates with additional regulatory mandates expected. The new regulatory requirements will increase the cost of offshore drilling and production operations. The increased regulations and cost of drilling operations could result in decreased drilling activity in the areas serviced by Southern Union. Furthermore, the imposed moratorium did result in some offshore drilling companies relocating their offshore drilling operations for currently indeterminable periods of time to regions outside of the United States. Business decisions to not drill in the areas serviced by Southern Union resulting from the increased regulations and costs could result in a reduction in the future development and production of natural gas reserves in the vicinity of Southern Union's facilities, which could adversely affect our business, financial condition, results of operations and cash flows.

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

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

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

Our business could be affected adversely by union disputes and strikes or work stoppages by Southern Union's and Sunoco's unionized employees.

As of December 31, 2012, approximately 37%, 45% and 7% of Southern Union's, Sunoco Logistics' and Sunoco's workforce, respectively, are covered by a number of collective bargaining agreements with various terms and dates of expirations. There can be no assurances that Southern Union or Sunoco will not experience a work stoppage in the future as a result of labor disagreements. Any work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on our business, financial position, results of operations or cash flows.

Governmental regulations and policies, particularly in the areas of taxation, energy and the environment, have a significant impact on our retail marketing business.

Federally mandated standards for use of renewable biofuels, such as ethanol and biodiesel in the production of refined products, are transforming traditional gasoline and diesel markets in North America. These regulatory mandates present production and logistical challenges for both the petroleum refining and ethanol industries, and may require us to incur additional capital expenditures or expenses particularly in our retail marketing business. We may have to enter into arrangements with other parties to meet our obligations to use advanced biofuels, with potentially uncertain supplies of these new fuels. If we are unable to obtain or maintain sufficient quantities of ethanol to support our blending needs, our sale of ethanol blended gasoline could be interrupted or suspended which could result in lower profits. There also will be compliance costs related to these regulations. We may experience a decrease in demand for refined petroleum products due to new federal requirements for increased fleet mileage per gallon or due to replacement of refined petroleum products by renewable fuels. In addition, tax incentives and other subsidies making renewable fuels more competitive with refined petroleum products may reduce refined petroleum product margins and the ability of refined petroleum products to compete with renewable fuels. A structural expansion of production capacity for such renewable biofuels could lead to significant increases in the overall production, and available supply, of gasoline and diesel in markets that we supply. In addition, a significant shift by consumers to more fuel-efficient vehicles or alternative fuel vehicles (such as ethanol or wider adoption of gas/electric hybrid vehicles), or an increase in vehicle fuel economy, whether as a result of technological advances by manufacturers, legislation mandating or encouraging higher fuel economy or the use of alternative fuel, or otherwise, also could lead to a decrease in demand, and reduced margins, for the refined petroleum products that we market and sell.

It is possible that any, or a combination, of these occurrences could have a material adverse effect on Sunoco's business or results of operations.

We have outsourced various functions related to our retail marketing business to third-party service providers, which decreases our control over the performance of these functions. Disruptions or delays of our third-party outsourcing partners could result in increased costs, or may adversely affect service levels. Fraudulent activity or misuse of proprietary data involving our outsourcing partners could expose us to additional liability.

Sunoco has previously outsourced various functions related to our retail marketing business to third parties and expects to continue this practice with other functions in the future.

While outsourcing arrangements may lower our cost of operations, they also reduce our direct control over the services rendered. It is uncertain what effect such diminished control will have on the quality or quantity of products delivered or services rendered, on our ability to quickly respond to changing market conditions, or on our ability to ensure compliance with all applicable domestic and foreign laws and regulations. We believe that we conduct appropriate due diligence before entering into agreements with our outsourcing partners. We rely on our outsourcing partners to provide services on a timely and effective basis. Although we continuously monitor the performance of these third parties and maintain contingency plans in case they are unable to perform as agreed, we do not ultimately control the performance of our outsourcing partners. Much of our outsourcing takes place in developing countries and, as a result, may be subject to geopolitical uncertainty. The failure of one or more of our third-party outsourcing partners to provide the expected services on a timely basis at the prices we expect, or as required by contract, due to events such as regional economic, business, environmental or political events, information technology system failures, or military actions, could result in significant disruptions and costs to our operations, which could materially adversely affect our business, financial condition, operating results and cash flow.

Our failure to generate significant cost savings from these outsourcing initiatives could adversely affect our profitability and weaken Sunoco's competitive position. Additionally, if the implementation of our outsourcing initiatives is disruptive to our retail marketing business, we could experience transaction errors, processing inefficiencies, and the loss of sales and customers, which could cause our business and results of operations to suffer.

As a result of these outsourcing initiatives, more third parties are involved in processing our retail marketing information and data. Breaches of security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about our retail marketing business or our clients, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose us to a risk of loss or misuse of this information, result in litigation and potential liability for us, lead to reputational damage to the Sunoco brand, increase our compliance costs, or otherwise harm our business.

Our operations could be disrupted if our information systems fail, causing increased expenses and loss of sales.

Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including our enterprise resource planning tools. We process a large number of transactions on a daily basis and rely upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, our operations and financial results could be affected adversely. Our systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. We have a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Our business interruption insurance may not compensate us adequately for losses that may occur.

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

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

The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of providing health care benefits for employees.

Certain of our subsidiaries provide pension plan and other postretirement healthcare benefits to certain of their employees. The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension and other postretirement fund values, changing demographics and fluctuating actuarial assumptions that may have a material adverse effect on the Partnership's future consolidated financial results. In addition, the passage of the Health Care Reform Act of 2010 could significantly increase the cost of health care benefits for our employees. While certain of the costs incurred in providing such pension and other postretirement healthcare benefits are recovered through the rates charged by the Partnership's regulated businesses, the Partnership's subsidiaries may not recover all of the costs and those rates are generally not immediately responsive to current market conditions or funding requirements. Additionally, if the current cost recovery mechanisms are changed or eliminated, the impact of these benefits on operating results could significantly increase.

Regency’s contract compression operations depend on particular suppliers and is vulnerable to parts and equipment shortages and price increases, which could have a negative impact on its results of operations.

The principal manufacturers of components for Regency’s natural gas compression equipment include Caterpillar, Inc. for engines, Air-X-Changers for coolers, and Ariel Corporation for compressors and frames. Regency’s reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. Regency also relies primarily on two vendors, Spitzer Industries Corp. and Standard Equipment Corp., to package and assemble its compression units. Regency does not have long-term contracts with these suppliers or packagers, and a partial or complete loss of certain of these sources could have a negative impact on Regency’s results of operations and could damage its customer relationships. In addition, since Regency expects any increase in component prices for compression equipment or packaging costs will be passed on to Regency, a significant increase in their pricing could have a negative impact on Regency’s results of operations.

Tax Risks to Common Unitholders

Our tax treatment depends on our continuing status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by individual states. If the IRS were to treat us, ETP or Regency as a corporation for federal income tax purposes or if we, ETP or Regency become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to Unitholders.

The anticipated after-tax economic benefit of an investment in our Common Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this matter. The value of our investments in ETP and Regency depends largely on ETP and Regency being treated as partnerships for federal income tax purposes.

Despite the fact that we, ETP and Regency are each a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. If we are so treated, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we would likely pay additional state income taxes as well. If ETP or Regency were treated as a corporation for federal income tax purposes for any taxable year for which the statute of limitations remains open or for any future taxable year, it would pay federal income tax on its taxable income at the corporate tax rate. Distributions to us would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to us. As a result, there would be a material reduction in the anticipated cash flow. In either case, our available cash would be substantially reduced.

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

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or to additional taxation as an entity for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

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

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

If the IRS contests the federal income tax positions we or our subsidiaries take, the market for our Common Units, ETP Common Units or Regency Common Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our Unitholders.

Neither we nor our subsidiaries have requested a ruling from IRS with respect to our treatment as partnerships for federal income tax purposes. The IRS may adopt positions that differ from the positions we or our subsidiaries take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we or our subsidiaries take. A court may not agree with some or all of the positions we or our subsidiaries take. Any contest with the IRS may materially and adversely impact the market for our Common Units, ETP's Common Units or Regency's Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us or our subsidiaries, and therefore indirectly by us, as a Unitholder and as the owner of the general partner of interests in ETP and Regency, reducing the cash available for distribution to our Unitholders.

Unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our Unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, Unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from the taxation of their share of our taxable income.

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

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

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

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, may be taxable to them as "unrelated business taxable income." Distributions to non-U.S. persons will be reduced by withholding taxes, generally at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal and state income tax returns and generally pay United States federal and state income tax on their share of our taxable income.

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

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

We treat each purchaser of Common Units as having the same tax benefits without regard to the actual Common Units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the Common Units.

Because we cannot match transferors and transferees of Common Units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our Unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to tax returns of our Unitholders. Moreover, because we have subsidiaries that are organized as C corporations for federal income tax purposes owns units in us, a successful IRS challenge could result in this subsidiary having a greater tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration

method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.
A Unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the Unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.
Because a Unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the

Table of Contents

period of the loan to the short seller and the Unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

ETP and Regency have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and the public Unitholders of ETP and Regency. The IRS may challenge this treatment, which could adversely affect the value of ETP’s or Regency’s Common Units and our Common Units.

When we, ETP or Regency issue additional units or engage in certain other transactions, we, ETP or Regency determine the fair market value of the assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of ETP’s and Regency’s Unitholders and us. Although ETP and Regency may from time to time consult with professional appraisers regarding valuation matters, including the valuation of its assets, ETP and Regency make many of the fair market value estimates of their assets themselves using a methodology based on the market value of their Common Units as a means to measure the fair market value of their assets. ETP’s or Regency’s methodology may be viewed as understating the value of ETP’s or Regency’s assets. In that case, there may be a shift of income, gain, loss and deduction between certain ETP or Regency Unitholders and us, which may be unfavorable to such ETP or Regency Unitholders. Moreover, under our current valuation methods, subsequent purchasers of our Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to ETP’s or Regency’s tangible assets and a lesser portion allocated to ETP’s or Regency’s intangible assets. The IRS may challenge ETP’s or Regency’s valuation methods, or our, ETP’s or Regency’s allocation of Section 743(b) adjustment attributable to ETP’s or Regency’s tangible and intangible assets, and allocations of income, gain, loss and deduction between us and certain of ETP’s or Regency’s Unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our Unitholders, the ETP Unitholders or the Regency Unitholders. It also could affect the amount of gain on the sale of Common Units by our Unitholders, ETP’s Unitholders or Regency’s Unitholders and could have a negative impact on the value of our Common Units or those of ETP or Regency or result in audit adjustments to the tax returns of our, ETP’s or Regency’s Unitholders without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve month period will result in the termination of our partnership for federal income tax purposes.

We will be considered technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit during the applicable twelve-month period will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all Unitholders which would require us to file two federal partnership tax returns (and our Unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a Unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such Unitholder’s taxable income for the year of termination. A technical termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes on the technical termination date, and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our Common Units.

In addition to federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we, ETP or Regency conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. We currently own property or conduct business in many states, most of which impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS
None.

ITEM 2. PROPERTIES
A description of our properties is included in "Item 1. Business." We and our subsidiaries own an executive office building in Dallas, Texas and office buildings in Houston and San Antonio, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

We believe that we have satisfactory title to or valid rights to use all of our material properties. Although some of our properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-competition agreements and immaterial encumbrances, easements and restrictions, we do not believe that any such burdens will materially interfere with our continued use of such properties in our business, taken as a whole. In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local government and regulatory authorities which relate to ownership of our properties or the operations of our business.

Substantially all of our subsidiaries' pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. Our subsidiaries have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee. ETP also owns and operates multiple natural gas and NGL storage facilities and owns or leases processing, treating and conditioning facilities in connection with its midstream operations.

ITEM 3. LEGAL PROCEEDINGS
Sunoco, along with other refiners, manufacturers and sellers of gasoline, is a defendant in lawsuits alleging MTBE contamination of groundwater. The plaintiffs typically include water purveyors and municipalities responsible for supplying drinking water and governmental authorities. The plaintiffs are asserting primarily product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. The plaintiffs in all of the cases are seeking to recover compensatory damages, and in some cases, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2012, Sunoco was a defendant in two lawsuits involving one state and Puerto Rico. These cases are venued in a multidistrict proceeding in a New York federal court. Both 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.

Discovery is proceeding in these cases. There has been insufficient information developed about the plaintiffs' legal theories or the facts in the natural resource damage claims that would be relevant to an analysis of the ultimate liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that the MBTE cases could have a significant impact on results of operations for any future period, but does not believe that the cases will have a material adverse effect on its consolidated financial position.

For a description of legal proceedings, see Note 11 to our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Parent Company

Market Price of and Distributions on Common Units and Related Unitholder Matters

The Parent Company's common units are listed on the NYSE under the symbol "ETE." The following table sets forth, for the periods indicated, the high and low sales prices per ETE Common Unit, as reported on the NYSE Composite Transaction Tape, and the amount of cash distributions paid per ETE Common Unit for the periods indicated.

	Price Range		Cash
	High	Low	Distribution [1]
Fiscal Year 2012:			
Fourth Quarter	$48.20	$41.72	$0.635
Third Quarter	46.07	39.91	0.625
Second Quarter	43.12	34.00	0.625
First Quarter	44.47	38.86	0.625
Fiscal Year 2011:			
Fourth Quarter	$42.00	$30.78	$0.625
Third Quarter	45.42	33.21	0.625
Second Quarter	47.34	38.77	0.625
First Quarter	45.47	37.27	0.560

(1) Distributions are shown in the quarter with respect to which they relate. For each of the indicated quarters for which distributions have been made, an identical per unit cash distribution was paid on any units subordinated to our Common Units outstanding at such time. Please see "– Cash Distribution Policy" below for a discussion of our policy regarding the payment of distributions.

Excludes the Series A Convertible Preferred Units issued in connection with the Regency Transactions in May 2010. See Note 7 to our consolidated financial statements.

Description of Units

As of January 31, 2013, there were approximately 156,134 individual common unitholders, which includes common units held in street name. Common units represent limited partner interest in us that entitle the holders to the rights and privileges specified in the Parent Company's Third Amended and Restated Agreement of Limited Partnership, as amended to date (the "Partnership Agreement").

As of December 31, 2012, common units represent an aggregate 99.75% limited partner interest in us. Our General Partner owns an aggregate 0.25% General Partner interest in us. Our common units are registered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and are listed for trading on the NYSE. Each holder of a common unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all common units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The common units are entitled to distributions of Available Cash as described below under "– Cash Distribution Policy".

Cash Distribution Policy

General. The Parent Company will distribute all of its "Available Cash" to its unitholders and its General Partner within 50 days following the end of each fiscal quarter.

Table of Contents

Definition of Available Cash. Available Cash is defined in the Parent Company's Partnership Agreement and generally means, with respect to any calendar quarter, all cash on hand at the end of such quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:

- provide for the proper conduct of its business;
- comply with applicable law and/or debt instrument or other agreement; and
- provide funds for distributions to unitholders and its General Partner in respect of any one or more of the next four quarters.

The total amount of distributions declared is reflected in Note 8 to our consolidated financial statements.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The selected historical financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and accompanying notes thereto included elsewhere in this report. The amounts in the table below, except per unit data, are in millions.

In October 2012, ETP sold ETC Canyon Pipeline, LLC ("ETC Canyon") for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from continuing operations and the prior year amounts have been adjusted to present Canyon's operations as discontinued operations.

In December 2012, Southern Union entered into a purchase and sale agreement with the Laclede Entities, pursuant to which Laclede Missouri has agreed to acquire the assets of Missouri Gas Energy division and Laclede Massachusetts has agreed to acquire the assets of the New England Gas Company division. For the period from our acquisition of Southern Union (March 26, 2012) to December 31, 2012 the results of operations of distribution operations have been adjusted to income from discontinued operations.

	Years Ended December 31,				
Statement of Operations Data:	2012	2011	2010	2009	2008
Total revenues	$16,964	$8,190	$6,556	$5,378	$9,236
Operating income	1,360	1,237	1,044	1,047	1,079
Income from continuing operations	1,383	531	345	692	675
Basic income from continuing operations per limited partner unit	1.17	1.39	0.87	1.97	1.67
Diluted income from continuing operations per limited partner unit	1.17	1.38	0.87	1.97	1.67
Cash distribution per unit	2.51	2.44	2.16	2.14	1.91
Balance Sheet Data (at period end):					
Total assets	48,904	20,897	17,379	12,161	11,070
Long-term debt, less current maturities	21,440	10,947	9,346	7,751	7,190
Total equity	16,350	7,388	6,248	3,220	2,339

Table of Contents

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

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 "Item 8. Financial Statements and Supplementary Data" of this report. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Item 1A. Risk Factors" of this report.

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, Southern Union, 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. In addition, we own a 60% interest in Holdco, as described below.

At December 31, 2012, our equity interests consisted of:

	General Partner Interest (as a % of total partnership interest)		Incentive Distribution Rights ("IDRs")		Limited Partner Units
ETP	0.9	%	100	%	50,226,967
Regency	1.6	%	100	%	26,266,791

The Parent Company's principal sources of cash flow have historically 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. Effective with the acquisition of Southern Union in March 2012, the Parent Company also generated cash flows through its wholly-owned subsidiary, Southern Union until its contribution of Southern Union to Holdco on October 5, 2012. Subsequent to October 5, 2012, we also generate cash flows from our direct investment in Holdco. The Parent Company's primary cash requirements are for distributions to its partners and holders of the Preferred Units, 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.

As a result of the Regency Transactions in May 2010, the Southern Union Merger in March 2012 and the Holdco Transaction in October 2012, the periods presented herein do not include activities from Regency, Southern Union or Sunoco prior to the consummation of the respective mergers and/or transactions.

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.

Subsequent to the Holdco Transaction on October 5, 2012, as described above, our reportable segments changed. Our reportable segments currently consist of the following:

- Reportable segments of ETP:

Natural gas operations, including the following:

natural gas midstream and intrastate transportation and storage through Southern Union and La Grange Acquisition, L.P., which conducts business under the assumed name of ETC OLP; and
interstate natural gas transportation and storage through ET Interstate and Southern Union. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Southern Union is the parent company of Panhandle, which provides transportation and storage services through the Panhandle, Trunkline and Sea Robin transmission systems.
NGL transportation, storage and fractionation services primarily through Lone Star.
Refined product and crude oil operations, including the following:
refined product and crude oil transportation through Sunoco Logistics; and
retail marketing of gasoline and middle distillates through Sunoco.
- Investment in Regency, including the consolidated operations of Regency.
- Corporate and Other, including the following:

activities of the Parent Company;
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.; and
ETP's corporate and other, which includes the following operating segments that do not meet the qualitative threshold for separate reporting:
natural gas compression services through ETC Compression;
a limited partner interest in AmeriGas;
a non-operating interest in PES;
natural gas distribution operations through Southern Union; and
approximately 30% non-operating interest in a refining joint venture.

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. ETP also controls Holdco.

Recent Developments

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

On March 26, 2012, we acquired all of the outstanding shares of Southern Union for approximately $3.01 billion in cash and approximately 57 million ETE Common Units. 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 2.25 million ETP Common Units.

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 approximately $2.6 billion in cash. Immediately following the closing of the Sunoco merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation, 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 90,706,000 ETP Class F Units representing limited partner interests in ETP. We refer to this as the "Holdco Transaction." Pursuant to a stockholders agreement between ETE and ETP, ETP controls Holdco. Consequently, ETP consolidates Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

In December 2012, Southern Union entered into a purchase and sale agreement pursuant to which subsidiaries of Laclede Gas Company, Inc. have agreed to acquire the assets of Southern Union's Missouri Gas Energy and New England Gas Company divisions. Total consideration for the acquisitions will be $1.035 billion, subject to customary closing adjustments, less the assumption of approximately $19 million of debt. On February 11, 2013, the Laclede Entities announced that it had entered into

Table of Contents

an agreement with Algonquin Power & Utilities Corp (APUC") that will allow a subsidiary of APUC to assume the right of the Laclede Entities to purchase the assets of Southern Union's New England Gas Company division, subject to certain approvals. It is expected that the transactions contemplated by the Purchase and Sale Agreements will close by the end of the third quarter of 2013.

On February 27, 2013, Southern Union entered into a definitive contribution agreement to contribute to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration to be paid by Regency in connection with this transaction will consist of (i) the issuance of 31,372,419 Regency common units to Southern Union, (ii) the issuance of 6,274,483 Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units will 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. Upon the closing of the transaction, we will agree to forego all distributions with respect to our IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing. The transaction is expected to close in the second quarter of 2013.

As we and our subsidiaries have completed several major strategic transactions since 2011 to expand our midstream service capabilities and to geographically diversity our asset platform, our focus is currently on the full integration and optimization of our diversified asset portfolio to enhance unitholder value. We expect to simplify our organization during 2013 and 2014 and possibly beyond. In order to take advantage of numerous asset optimization opportunities, we may consider potential transactions among us and our subsidiaries and/or affiliates.

In addition, we expect to benefit from continued growth among our existing consolidated subsidiaries. Aggregate growth capital expenditures among our consolidated subsidiaries totaled $3.52 billion in 2012, and we expect that amount to be between $2.06 billion and $2.36 billion in 2013. Our announced growth projects include a second fractionator at Mont Belvieu and expansion in the Eagle Ford Shale and Permian Basin. Along with the inherent benefits of greater scale and cash flow diversification that we experience from growth projects, we also expect to benefit in 2013 from the full-year impacts of the recent Southern Union and Sunoco acquisitions as well as additional synergies that may be created as we continue to streamline the organization.

Results of Operations

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

We previously reported net income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, 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.

Based on the change in our segment performance measure, we have adjusted the presentation of our segment results for the prior years to be consistent with the current year presentation.

Table of Contents

Consolidated Results

	Years Ended December 31,		
	2012	2011	Change
Segment Adjusted EBITDA:			
Intrastate Transportation	$601	$667	$(66)
Interstate Transportation and Storage	1,013	373	640
Midstream	438	389	49
NGL Transportation and Services	209	127	82
Retail Marketing	109	—	109
Investment in Sunoco Logistics	219	—	219
Investment in Regency	480	422	58
Corporate and Other	36	153	(117)
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 reserve	(75)	—	(75)
Losses on extinguishments of debt	(123)	—	(123)
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on extinguishment of debt and taxes	(435)	(114)	(321)
Adjusted EBITDA related to discontinued operations	(99)	(23)	(76)
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 the following:

- 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.

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

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

Table of Contents

- interest expense of $14 million and $9 million recorded by Sunoco Logistics and Sunoco, 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 Reserve. A LIFO valuation reserve was 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.
Proportionate Share of Unconsolidated Affiliates' Interest, Depreciation, Amortization, Non-cash Compensation Expense, Loss on Debt Extinguishment and Taxes. 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.
Adjusted EBITDA Attributable 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.
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.

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 Sunoco Merger and Holdco Transaction for the year ended December 31, 2012 and 2011, giving effect that each occurred on January 1, 2011. This unaudited pro forma financial information is provided to supplement the discussion and analysis of the historical financial information and should be read in conjunction with such historical financial information. This unaudited pro forma information is for illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Sunoco Merger and Holdco Transaction had been consummated on January 1, 2011.

Table of Contents

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 - natural gas operations	14,153	(80)	33,142	302	(11,193)	36,324
Depreciation and amortization	871	(4)	168	49	76	1,160
Selling, general and administrative	580	(1)	459	11	(119)	930
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)
Gains (losses) on non-hedged interest rate derivatives	(19)	—	—	—	—	(19)
Impairment charges	—	—	—	—	—	—
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

Table of Contents

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 - natural gas operations	6,075	(1,174)	44,119	1,338	(16,677)	33,681
Depreciation and amortization	586	(78)	335	204	(2)	1,045
Selling, general and administrative	292	(47)	598	42	(18)	867
Impairment charges	—	—	2,629	—	(2,569)	60
Total costs and expenses	6,953	(1,299)	47,681	1,584	(19,266)	35,653
OPERATING INCOME	1,237	(128)	(2,353)	413	2,738	1,907
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	2,607	965
Income tax expense (benefit)	17	(4)	(1,063)	80	1,070	100
INCOME FROM CONTINUING OPERATIONS	$531	$(14)	$(1,403)	$214	$1,537	$865

(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.

Table of Contents

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas MMBtu/d — transported	9,849,900	11,295,084	(1,445,184)
Revenues	$2,191	$2,674	$(483)
Cost of products sold	1,394	1,774	(380)
Gross margin	797	900	(103)
Unrealized losses on commodity risk management activities	19	9	10
Operating expenses, excluding non-cash compensation expense	(173)	(191)	18
Selling, general and administrative, excluding non-cash compensation expense	(43)	(54)	11
Adjusted EBITDA related to unconsolidated affiliates	1	3	(2)
Segment Adjusted EBITDA	$601	$667	$(66)

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

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

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

Our 2012 margin decreased as compared to 2011 due to the net impact of the following factors:

- Transport fees decreased primarily due to a decrease in transported volumes as unfavorable market conditions continued and the cessation of certain long-term transportation contracts;
- From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $28 million in 2012 compared to $36 million in 2011. The decrease of $8 million between periods was primarily due to a reduction in the amount of capacity utilized by our marketing affiliate;
- Margin from natural gas sales and other activity decreased primarily due to a decline of $30 million in margin where we utilize third party processing, offset by increased margin of $13 million from wellhead purchases in the Eagle Ford Shale that were sold to end users on our HPL system and increased margin of $4 million from system optimization and other operational activities;
- The margin from the natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. Excluding derivatives related to storage, unrealized gains of $13 million were recorded in 2012 as compared to unrealized losses of $21 million in 2011; and
- Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased $51 million due to less retained volumes and a $37 million decline in the average of natural gas spot prices.

Table of Contents

Storage margin was comprised of the following:

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

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

Unrealized Losses on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities reflect the net impact from unrealized gains and losses on storage and non-storage derivatives, as well as fair value adjustments on inventory. For 2012, unrealized losses on derivatives of $46 million were offset by fair value adjustments to storage gas inventory of $27 million. For 2011, unrealized losses reflected fair value adjustments to storage gas inventory of $52 million, offset by gains on derivatives of $42 million.

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

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses decreased between the periods primarily due to a decrease in employee-related costs and allocated overhead expenses.

Interstate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d):			
ETP Legacy Assets	2,978,410	2,800,655	177,755
Southern Union transportation and storage	3,832,929	—	3,832,929
Natural gas sold (MMBtu/d)	18,065	22,405	(4,340)
Revenues	$1,109	$447	$662
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(244)	(93)	(151)
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(156)	(34)	(122)
Adjusted EBITDA related to unconsolidated affiliates	304	53	251
Segment Adjusted EBITDA	$1,013	$373	$640

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

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

73

Table of Contents

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Substantially all of the increase in 2012 compared to 2011 was due to the consolidation of Southern Union's transportation and storage business beginning March 26, 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Substantially all of the increase in 2012 compared to 2011 was due to the consolidation of Southern Union's transportation and storage business beginning March 26, 2012.

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

Midstream

	Years Ended December 31,		
	2012	2011	Change
Gathered volumes (MMBtu/d):			
ETP Legacy Assets	2,364,133	2,020,126	344,007
Southern Union gathering and processing	510,061	—	510,061
NGLs produced (Bbls/d):			
ETP Legacy Assets	79,640	54,246	25,394
Southern Union gathering and processing	41,163	—	41,163
Equity NGLs produced (Bbls/d):			
ETP Legacy Assets	17,314	16,385	929
Southern Union gathering and processing	7,437	—	7,437
Revenues	$3,084	$2,543	$541
Cost of products sold	2,432	2,072	360
Gross margin	652	471	181
Unrealized (gains) losses on commodity risk management activities	2	(3)	5
Operating expenses, excluding non-cash compensation expense	(151)	(83)	(68)
Selling, general and administrative, excluding non-cash compensation expense	(73)	(19)	(54)
Adjusted EBITDA related to unconsolidated affiliates	(7)	—	(7)
Adjusted EBITDA related to discontinued operations	15	23	(8)
Segment Adjusted EBITDA	$438	$389	$49

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

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

	Years Ended December 31,		
	2012	2011	Change
Gathering and processing fee-based revenues	$339	$253	$86
Non fee-based contracts and processing	335	234	101
Other	(22)	(16)	(6)
Total gross margin	$652	$471	$181

74

Table of Contents

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

- Gathering and processing fee-based revenues. Increased volumes from production in the Eagle Ford Shale resulted in increased fee-based revenues of $70 million in 2012 as compared to 2011, partially offset by declines in the Fort Worth Basin that affected our North Texas system resulting in a $5 million decline from 2012 to 2011. Additionally, Southern Union's gathering and processing segment contributed $20 million of fee-based revenue during March 26, 2012 through December 31, 2012.
- Non fee-based contracts and processing margin. We recorded $125 million of incremental non-fee based revenue in connection with the consolidation of Southern Union's gathering and processing business from March 26, 2012 through December 31, 2012. Excluding these incremental revenues from Southern Union's gathering and processing business, our non fee-based gross margins decreased $24 million primarily due to lower NGL prices. The composite NGL price for 2012 was $0.96 per gallon as compared to $1.30 per gallon in 2011.
- Other midstream gross margin. We recorded derivative losses of $2 million in 2012 associated with our marketing activities compared to derivative gains of $4 million in 2011 resulting in a decline of $6 million from 2012 compared to 2011. For the years ended December 31, 2012 and 2011, other midstream margin included $28 million and $36 million, respectively, of fees charged by our intrastate transportation systems. These fees were recognized as income by our intrastate transportation and storage segment and have no effect on our consolidated results of operations.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized losses of $2 million in 2012 associated with our marketing activities compared to unrealized gains of $3 million in 2011 mainly due to lower notional volumes hedged compared to the prior year.

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

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to consolidation of Southern Union's gathering and processing operations effective March 26, 2012. In addition, additional assets placed into service in the Eagle Ford Shale also caused a slight increase. For the periods presented, selling, general and administrative expenses increased $38 million due to consolidation of Southern Union's gathering and processing operations. Increases related to new assets in the Eagle Ford Shale were higher due to employee costs of $7 million, an increase in insurance costs of $2 million, an increase in professional fees of $1 million, an increase in information technology costs of $3 million and an increase in office expenses of $2 million.

NGL Transportation and Services

	Years Ended December 31,		
	2012	2011	Change
NGL transportation volumes (Bbls/d)	172,569	132,862	39,707
NGL fractionation volumes (Bbls/d)	17,754	16,475	1,279
Revenues	$650	$397	$253
Cost of products sold	361	218	143
Gross margin	289	179	110
Operating expenses, excluding non-cash compensation expense	(60)	(39)	(21)
Selling, general and administrative, excluding non-cash compensation expense	(20)	(13)	(7)
Segment Adjusted EBITDA	$209	$127	$82

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

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

Table of Contents

December 31, 2011 at our Geismar fractionation complex in Louisiana due to less refinery downtime in 2012 as compared to the comparable prior year period.
Gross Margin. The components of our NGL transportation and services segment gross margin were as follows:

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

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

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

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

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

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

ETP acquired its retail marketing segment on October 5, 2012 in connection with ETP's acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

Table of Contents

Investment in Sunoco Logistics

	Years Ended December 31		
	2012	2011	Change
Revenue	$3,194	$—	$3,194
Cost of products sold	2,843	—	2,843
Gross margin	351	—	351
Unrealized losses on commodity risk management activities	(15)	—	(15)
Operating expenses, excluding non-cash compensation expense	(95)	—	(95)
Selling, general and administrative, excluding non-cash compensation expense	(32)	—	(32)
Adjusted EBITDA related to unconsolidated affiliates	10	—	10
Segment Adjusted EBITDA	$219	$—	$219

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

Investment in Regency

	Years Ended December 31,		
	2012	2011	Change
Revenues	$1,339	$1,434	$(95)
Cost of products sold	871	1,013	(142)
Gross margin	468	421	47
Unrealized losses (gains) on commodity risk management activities	(5)	—	(5)
Operating expenses, excluding non-cash compensation expense	(166)	(147)	(19)
Selling, general and administrative, excluding non-cash compensation expense	(58)	(64)	6
Adjusted EBITDA related to unconsolidated affiliates	227	213	14
Other	14	(1)	15
Segment Adjusted EBITDA	$480	$422	$58

Gross Margin. Regency's gross margin increased $47 million primarily due to increased volumes in Regency's South and West Texas and North Louisiana gathering and processing operations.

Unrealized Losses (Gains) on Commodity Risk Management Activities. Regency's losses 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 primarily due 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, decreased approximately $5 million as a result of lower professional fees and lower rent expense, which was partially offset by a $2 million increase in employee expenses for management incentive plan expenses and employee benefits.

Adjusted EBITDA Related to Unconsolidated Affiliates. Regency's adjusted EBITDA attributable to unconsolidated affiliates increased $14 million 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 $16 million one-time producer payment received in March 2012 related to an assignment of certain contracts, which was partially offset by lower non-cash mark-to-market gains on the embedded derivatives related to Regency's preferred units.

Table of Contents

Corporate and Other

	Years Ended December 31		
	2012	2011	Change
Revenue	$408	$1,656	$(1,248)
Cost of products sold	320	1,016	(696)
Gross margin	88	640	(552)
Unrealized losses on commodity risk management activities	3	4	(1)
Operating expenses, excluding non-cash compensation expense	(57)	(355)	298
Selling, general and administrative, excluding non-cash compensation expense	(168)	(82)	(86)
Adjusted EBITDA related to unconsolidated affiliates	166	—	166
Adjusted EBITDA related to discontinued operations	84	—	84
Adjustments and Eliminations	(80)	(54)	(26)
Segment Adjusted EBITDA	$36	$153	$(117)

For 2012, our Corporate and Other segment included the operations of the Parent Company, the operations of Southern Union's distribution operations, as well as certain other businesses. For 2011, our Corporate and Other segment also included our retail propane and other retail propane business, which was contributed to AmeriGas in January 2012. Substantially all of the variances were attributable to the changes in the components of the Corporate and Other segment between the periods.

Table of Contents

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

We previously reported net income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, 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.

Based on the change in our segment performance measure, we have adjusted the presentation of our segment results for the prior years to be consistent with the current year presentation.

Consolidated Results

	Years Ended December 31,		
	2011	2010	Change
Segment Adjusted EBITDA:			
Intrastate Transportation	$667	$716	$(49)
Interstate Transportation and Storage	373	220	153
Midstream	389	329	60
NGL Transportation and Services	127	—	127
Investment in Regency	422	218	204
Corporate and Other	153	255	(102)
Total	2,131	1,738	393
Depreciation and amortization	(586)	(406)	(180)
Interest expense, net of interest capitalized	(740)	(625)	(115)
Losses on non-hedged interest rate derivatives	(78)	(52)	(26)
Non-cash unit-based compensation expense	(42)	(31)	(11)
Unrealized gains (losses) on commodity risk management activities	7	(110)	117
Losses on extinguishments of debt	—	(16)	16
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on extinguishment of debt and taxes	(114)	(71)	(43)
Adjusted EBITDA related to discontinued operations	(23)	(19)	(4)
Other, net	(7)	(49)	42
Income from continuing operations before income tax expense	548	359	189
Income tax expense	17	14	3
Income from continuing operations	531	345	186
Loss from discontinued operations	(3)	(8)	5
Net income	$528	$337	$191

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

Depreciation and Amortization. Depreciation and amortization increased due to acquisitions and assets placed in service since 2010. Depreciation and amortization increased by $28 million for ETP’s interstate transportation operations primarily due to the Tiger pipeline which was placed in service in December 2010. Depreciation and amortization increased by $25 million for ETP’s midstream operations primarily due to incremental depreciation from the continued expansion of its Northern Louisiana and

Table of Contents

Southeast Texas assets. Depreciation and amortization for ETP's NGL transportation and services operations was $33 million from its inception in May 2011 through December 31, 2011.

In addition, depreciation and amortization increased in 2011 as a result of the consolidation of Regency beginning May 26, 2010.

Interest Expense, Net of Interest Capitalized. For the year ended December 31, 2011 compared to the year ended December 31, 2010, interest expense increased primarily due to the following:

- ETP's issuance of $1.5 billion of senior notes in May 2011, the proceeds from which were used to repay borrowings on its revolving credit facility, to fund growth projects and for general partnership purposes;
- As a result of the consolidation of Regency beginning May 26, 2010; and
- Distributions on the Preferred Units issued by ETE in connection with the acquisition of a controlling interest in Regency in May 2010. Distributions on the Preferred Units were $24 million and $14 million for the years ended December 31, 2011 and 2010, respectively.

The above mentioned increases in interest were partially offset by a decrease in interest expense at the Parent Company primarily due to the recognition of $66 million of realized losses on hedged interest rate swaps in September 2010 in connection with the refinancing of indebtedness that would have come due in 2011 and 2012. These realized losses were offset by an increase in interest expense that primarily resulted from the Parent Company's issuance of $1.8 billion of aggregate principal amount of 7.5% senior notes in September 2010.

Losses on Non-Hedged Interest Rate Derivatives. In September 2010, the Parent Company terminated its interest swaps that were not accounted for as hedges in connection with its issuance of $1.8 billion of senior notes. Prior to that settlement, changes in the fair value of and cash payments related to these swaps were recorded directly in earnings.

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

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

Proportionate Share of Unconsolidated Affiliates' Interest, Depreciation, Amortization, Non-cash Compensation Expense, Loss on Debt Extinguishment and Taxes. Amounts reflected for 2011 primarily include our proportionate share of such amounts related to FEP, HPC and MEP. The 2010 amounts primarily represented our proportionate share of such amounts and do not include HPC prior to the Regency Transaction in May 2010.

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

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	11,295,084	12,251,457	(956,373)
Revenues	$2,674	$3,291	$(617)
Cost of products sold	1,774	2,381	(607)
Gross margin	900	910	(10)
Unrealized losses on commodity risk management activities	9	62	(53)
Operating expenses, excluding non-cash compensation expense	(191)	(196)	5
Selling, general and administrative, excluding non-cash compensation expense	(54)	(63)	9
Adjusted EBITDA related to unconsolidated affiliates	3	3	$—

Segment Adjusted EBITDA	$667	$716	(49)

Table of Contents

Volumes. Transported volumes decreased due to a less favorable natural gas price environment and lower basis differentials primarily between the West and East Texas market hubs offset by increased volumes from rich natural gas shale formations primarily in the Eagle Ford and certain areas of the Barnett Shale. The average spot price difference between these locations was $0.036/MMBtu in 2011 compared to $0.127/MMBtu in 2010.
Gross Margin. The components of ETP's intrastate transportation and storage segment gross margin were as follows:

	Years Ended December 31,		
	2011	2010	Change
Transportation fees	$599	$594	$5
Natural gas sales and other	107	110	(3)
Retained fuel revenues	130	144	(14)
Storage margin, including fees	64	62	2
Total gross margin	$900	$910	$(10)

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

- Additional demand-based contracts offset a decline in transported volumes, resulting in a net increase of $5 million in transportation fees.
- From time to time, ETP's marketing affiliate will contract with its intrastate pipelines for long-term and interruptible transportation capacity. The intrastate transportation and storage segment recorded intercompany transportation fees from ETP's marketing affiliate of $36 million in 2011 compared to $40 million in 2010. The decrease of $4 million between periods was primarily due to a reduction in the amount of capacity utilized by ETP's marketing affiliate.
- Margin from natural gas sales and other activity decreased $3 million primarily due to unfavorable impacts from system optimization activities.

The margin from the natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. During the fourth quarter of 2011, intrastate's trading activities included the use of financial commodity derivatives. Excluding derivatives related to storage, unrealized losses of $21 million were recorded in 2011 compared to unrealized losses of $13 million in 2010.

- Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased $14 million due to less volumes and a decline in average natural gas spot prices, which averaged $4.03/MMBtu in 2011 compared to an average of $4.35/MMBtu in 2010.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2011	2010	Change
Withdrawals from storage natural gas inventory (MMBtu)	24,517,008	39,784,446	(15,267,438)
Margin on physical sales	$11	$69	$(58)
Settlements of derivatives	8	1	7
Realized margin on natural gas inventory transactions	19	70	(51)
Fair value adjustments	(52)	(57)	5
Unrealized gains (losses) on derivatives	63	9	54
Margin recognized on natural gas inventory, including related derivatives	30	22	8
Revenues from fee-based storage	35	41	(6)
Other costs	(1)	(1)	—
Total storage margin	$64	$62	$2

The increase in ETP's storage margin was principally driven by gains in derivatives offsetting a decline in the margin on physical sale due to a decrease in withdrawals of natural gas from ETP's Bammel storage facility as a result of warmer than normal weather

Table of Contents

patterns. Additionally, ETP experienced a decline in fee-based storage revenue due to the cessation in 2011 of fixed fee contracts representing 4.5 Bcf of storage capacity.
Unrealized Losses on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities reflect the net impact from unrealized gains and losses on storage and non-storage derivatives, as well as fair value adjustments on inventory. Unrealized losses decreased primarily due to the timing of storage withdrawals and declining forward prices. ETP also recorded additional mark-to-market losses of $8 million in 2011 not related to storage.
Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased between the periods primarily due to a decrease in the cost of natural gas consumed of $1 million due to lower gas prices and a decrease of $7 million in operating and maintenance expense compared to 2010. These decreases were partially offset by higher ad valorem taxes of $2 million due to expansions on ETP's HPL system and increased employee costs of $3 million.
Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses decreased between the periods primarily due to a decrease in allocated overhead expenses. A lower amount of overhead expenses were allocated to the intrastate transportation and storage segment in 2011 because of growth in other segments and the addition of NGL transportation and services segment.
Interstate Transportation and Storage

	Years Ended December 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	2,800,655	1,616,762	1,183,893
Natural gas sold (MMBtu/d)	22,405	23,760	(1,355)
Revenues	$447	$292	$155
Operating expenses, excluding non-cash compensation expense	(93)	(84)	(9)
Selling, general and administrative, excluding non-cash compensation expense	(34)	(20)	(14)
Adjusted EBITDA related to unconsolidated affiliates	53	32	21
Segment Adjusted EBITDA	$373	$220	$153

Volumes. Transported volumes for ETP's interstate transportation and storage segment increased primarily due to an increase in transported volumes of 1,270,656 MMBtu/d on the Tiger pipeline in 2011. The Tiger pipeline was placed in service in December 2010, and the Tiger pipeline expansion was placed in service on August 1, 2011. The incremental transported volumes related to the Tiger pipeline were offset by lower volumes on the Transwestern pipeline.

Revenues. Interstate transportation and storage revenues increased as a result of incremental revenues from the Tiger pipeline and related expansion. Revenues from the Tiger pipeline totaled $188 million in 2011 compared to $10 million in 2010. The incremental revenues from the Tiger pipeline were offset by a decrease in revenues from the Transwestern pipeline of $23 million due to decreases in transportation fees and operations gas sales as a result of lower volumes and prices.
Operating Expenses, Excluding Non-Cash Compensation Expense. Interstate transportation and storage operating expenses increased primarily due to operating expenses incurred on the Tiger pipeline.
Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Interstate transportation and storage selling, general and administrative expenses increased primarily due to increased allocated and employee-related expenses, including incremental amounts related to the Tiger pipeline.
Adjusted EBITDA Related to Unconsolidated Affiliates. Amounts reflected for 2011 primarily represent ETP's proportionate share of such amounts recorded by FEP. Amounts reflected for 2010 primarily represent ETP's proportionate share of such amounts recorded by MEP. ETP transferred substantially all of its interests in MEP to ETE on May 26, 2010, prior to which ETP held a 50% interest in MEP. ETP recorded equity in earnings related to

FEP of $24 million in 2011 and equity in earnings related to MEP of $9 million in 2010. In 2011, FEP recorded (on a 100% basis) revenues of $122 million and net income of $48 million.

Table of Contents

Midstream

	Years Ended December 31,		
	2011	2010	Change
Gathered volumes (MMBtu/d)	2,020,126	1,345,860	674,266
NGLs produced (Bbls/d)	54,246	50,602	3,644
Equity NGLs produced (Bbls/d)	16,385	18,870	(2,485)
Revenues	$2,543	$3,128	$(585)
Cost of products sold	2,072	2,750	(678)
Gross margin	471	378	93
Unrealized (gains) losses on commodity risk management activities	(3)	13	(16)
Operating expenses, excluding non-cash compensation expense	(83)	(66)	(17)
Selling, general and administrative, excluding non-cash compensation expense	(19)	(15)	(4)
Adjusted EBITDA related to discontinued operations	23	19	4
Segment Adjusted EBITDA	$389	$329	$60

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

Gross Margin. The components of ETP's midstream segment gross margin were as follows:

	Years Ended December 31,		
	2011	2010	Change
Gathering and processing fee-based revenues	$253	$198	$55
Non fee-based contracts and processing	234	200	34
Other	(16)	(20)	4
Total gross margin	$471	$378	$93

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

- Gathering and processing fee-based revenues. Increased volumes from production in the Eagle Ford Shale resulted in increased fee-based revenues of $26 million. Additionally, increased volumes from the growth of ETP assets in West Virginia and Louisiana provided an increase in ETP's fee-based margin of $18 million.

- Non fee-based contracts and processing margin. ETP's non fee-based gross margins increased $49 million primarily due to higher NGL prices. The composite NGL price for 2011 was $1.30 per gallon as compared to $1.02 per gallon in 2010. Lower equity NGL production volumes partially offset this increase.

- Other midstream gross margin. The increase in other midstream gross margin was due to increased margin associated with processing where third party processing was utilized. Additionally, ETP recorded unrealized gains of $3 million in 2011 associated with marketing activities compared to unrealized losses of $13 million in 2010. For the years ended December 31, 2011 and 2010, other midstream margin was net of $36 million and $40 million, respectively, of fees charged by ETP intrastate transportation systems. These fees were recognized as income by ETP's intrastate transportation and storage segment and have no effect on ETP's consolidated results of operations.

Unrealized (Gains) Losses on Commodity Risk Management Activities. ETP's midstream segment recorded unrealized gains of $3 million in 2011 compared to unrealized losses of $13 million in 2010 primarily due to a decrease in the volume of hedging activities of ETP's marketing affiliate.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased $18 million primarily due to an increase in maintenance and operating expenses of $7 million, an increase in ad valorem taxes of $4 million, an increase

83

Table of Contents

in employee expenses of $5 million and an increase in professional fees of $2 million. These increases primarily resulted from new assets placed into service in the Eagle Ford Shale.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to increases in professional fees of $4 million and other costs of $2 million offset by a decrease in employee costs of $2 million.

NGL Transportation and Services

	Years Ended December 31,		
	2011	2010	Change
NGL transportation volumes (Bbls/d)	132,862	—	132,862
NGL fractionation volumes (Bbls/d)	16,475	—	16,475
Revenues	$397	$—	$397
Cost of products sold	218	—	218
Gross margin	179	—	179
Operating expenses, excluding non-cash compensation expense	(39)	—	(39)
Selling, general and administrative, excluding non-cash compensation expense	(13)	—	(13)
Segment Adjusted EBITDA	$127	$—	$127

ETP owns a controlling interest in Lone Star, which acquired all of the membership interests in LDH on May 2, 2011. Results reflected above represent 100% of those of acquired businesses that are engaged in NGL transportation, storage and fractionation from May 2, 2011 to December 31, 2012.

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

	Years Ended December 31		
	2011	2010	Change
Storage revenues	$93	$—	$93
Transportation revenues	33	—	33
Processing and fractionation revenues	53	—	53
Total gross margin	$179	$—	$179

Retail Marketing

ETP acquired its retail marketing segment on October 5, 2012 as a result of its acquisition of Sunoco. Therefore no comparative information for the years ended December 31, 2011 or 2010 is available for this segment.

Investment in Sunoco Logistics

ETP obtained control of Sunoco Logistics on October 5, 2012 as a result of its acquisition of Sunoco. Therefore no comparative information for the years ended December 31, 2011 or 2010 is available for this segment.

Table of Contents

Investment in Regency

	Years Ended December 31,		
	2011	2010	Change
Revenues	$1,434	$716	$718
Cost of products sold	1,013	504	509
Gross margin	421	212	209
Unrealized losses (gains) on commodity risk management activities	—	23	(23)
Operating expenses	(147)	(78)	(69)
Selling, general and administrative, excluding non-cash compensation expense	(64)	(44)	(20)
Adjusted EBITDA related to unconsolidated affiliates	213	102	111
Other	(1)	3	(4)
Segment Adjusted EBITDA	$422	$218	$204

ETE obtained control of Regency on May 26, 2010. Changes between the year ended December 31, 2011 and the period from May 26, 2010 to December 31, 2010 were primarily due to the consolidation of Regency beginning May 26, 2010.

Corporate and Other

	Years Ended December 31		
	2011	2010	Change
Revenue	$1,656	$1,707	$(51)
Cost of products sold	1,016	1,010	6
Gross margin	640	697	(57)
Unrealized losses on commodity risk management activities	4	3	1
Operating expenses, excluding non-cash compensation expense	(355)	(349)	(6)
Selling, general and administrative, excluding non-cash compensation expense	(82)	(72)	(10)
Adjustments and eliminations	(54)	(24)	(30)
Segment Adjusted EBITDA	$153	$255	$(102)

For 2011 and 2010, our Corporate and Other segment included our retail propane and other retail propane business, the operations of the Parent Company, as well as certain other businesses. As discussed below, substantially all of the variances in the Corporate and Other segment were attributable to the retail propane and other retail propane related business. In January 2012, we contributed the propane business to AmeriGas.

Gross Margin. Total gross margin for our retail propane and other retail propane related business decreased $37 million primarily due to a decrease of $4 million in retail fuel margins related to a decline in the average gross margin per gallon sold as well as a decrease of $35 million due to lower volumes as a result of warmer weather and customer conservation. Total propane gross margin also decreased $1 million due to an unfavorable non-cash impact between periods attributable to mark-to-market adjustments on financial instruments used in our commodity price risk management activities. These decreases were slightly offset by a $3 million increase in other retail propane related gross profit.

Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses for our retail propane and other retail propane related business increased $8 million due to increases in net business insurance reserves and claims, $7 million in vehicle fuel and repair expenses and $1 million in general business taxes. These increases were partially offset by decreases of $5 million in performance-based bonus accruals, $2 million in employee wages and benefits and $3 million in other general operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Selling, general and administrative expenses for our retail propane and other retail propane related business increased $4 million primarily due to increases in allocated overhead expenses of $2 million and increases in employee wages and benefits of $2 million.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Overview

Parent Company Only

The Parent Company’s principal sources of cash flow have historically derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency. From the closing of the acquisition of Southern Union on March 26, 2012 until the closing of the Holdco Transaction on October 5, 2012, the Parent Company also has generated cash flows through Southern Union, as a wholly-owned subsidiary. Subsequent to the closing of the Holdco Transaction on October 5, 2012, the Parent Company's cash flows derived from its investments in ETP and Regency, as well as its direct ownership of 60% of Holdco. 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 the Citrus Acquisition, we have relinquished an aggregate $220 million of incentive distributions to be received from ETP over 16 consecutive quarters, approximately $14 million per quarter, beginning with the distribution paid in May 2012 for the quarter ended March 31, 2012. Also, in connection with the Holdco Transaction, we have relinquished an aggregate $210 million of incentive distributions to be received from ETP over 12 consecutive quarters, approximately $18 million per quarter, beginning with the distribution paid in November 2012 for the quarter ended September 30, 2012.

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 issued a $2.0 billion Senior Secured Term Loan as permanent financing to fund the cash portion of the Southern Union Merger and pay related fees and expenses, including existing borrowings under our revolving credit facility and for general partnership purposes. We also used a portion of the cash received from ETP in the Citrus Acquisition to fund the remaining cash portion of the Southern Union Merger.

We expect ETP, Regency 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.

Table of Contents

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 the following capital expenditures in 2013:

	Growth		Maintenance [2]	
	Low	High		
ETP Legacy Assets:				
Midstream and intrastate transportation and storage	$ 250	$ 300	$ 80	$ 85
NGL transportation and services [1]	400	500	15	20
Interstate transportation and storage	10	20	25	30
Total ETP legacy assets capital expenditures	660	820	120	135
Holdco:				
Southern Union transportation and storage	20	30	90	105
Southern Union gathering and processing	170	190	10	15
Sunoco retail marketing	30	60	70	80
Total Holdco legacy assets capital expenditures	220	280	170	200
Investment in Sunoco Logistics	650	750	60	65
Total expected capital expenditures	$ 1,530	$ 1,850	$ 350	$ 400

(1) We expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $100 million and $150 million.

(2) Includes (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; (iii) capital expenditures related to NGL transportation and services, including amounts expected to be funded by Regency related to its 30% interest in Lone Star; and (iv) capital expenditures related to our crude and retail marketing operations.

(3) Includes capital expenditures related to SUGS through the expected closing date for the pending contribution transaction with Regency.

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, replacing pipe caused by delays from 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.

In January 2013, ETP issued senior notes to repay borrowings outstanding under its revolving credit facility and for general partnership purposes.

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. 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 credit facilities. In January 2013, the balances outstanding under the Sunoco Logistics' credit facilities were repaid in connection with a Senior Notes offering. Sunoco Logistics' capital position reflects crude oil and refined products inventories based on historical costs under the LIFO method of accounting. Sunoco Logistics periodically supplements its cash flows from operations with proceeds from debt and equity financing activities.

In addition to the above capital resources, as of December 31, 2012, Southern Union had available capacity under its revolving credit facility.

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 2013, Regency expects to invest $400 million in growth capital expenditures, of which $185 million is expected to be invested in organic growth projects in the gathering and processing operations; $120 million is expected to be invested in Regency's portion of growth capital expenditures for Lone Star; $80 million is expected to be invested in the fabrication of new compressor packages for Regency's contract compression operations; and $15 million is expected to be invested in the fabrication of new treating plants for Regency's contract treating operations. In addition, Regency expects to invest $35 million in maintenance capital expenditures in 2013, 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 for ETP’s and Regency’s 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.

For the discussion that follows, certain amounts in prior periods have been reclassified to conform to the 2012 presentation.

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 result from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring, such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when 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, 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 $687 million and changes in operating assets and liabilities of $158 million. The difference between net income and the net cash provided by operating activities also included distributions received from affiliates that exceeded equity in earnings by $3 million. The non-cash activity consisted primarily of depreciation and amortization of $612 million and non-cash compensation expense of $42 million.

Year Ended December 31, 2010
Cash provided by operating activities in 2010 was $1.09 billion and net income was $337 million. The difference between net income and cash provided by operating activities in 2010 consisted of non-cash items totaling $553 million and changes in operating assets and liabilities of $260 million. The difference between net income and the net cash provided by operating activities also included ETP interest rate swap termination proceeds of $26 million, ETE payments to terminate interest rate swaps of $169 million and distributions received from our affiliates that exceeded our equity in earnings by $80 million. The non-cash activity consisted primarily of depreciation and amortization of $431 million and an impairment in ETP's investment of an affiliate of $53 million. In addition, non-cash compensation expense was $31 million. These amounts are partially offset by the allowance for equity funds used during construction of $29 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, 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 $2.70 billion for growth capital expenditures and $143 million for maintenance capital expenditures during 2012. Regency invested $767 million for growth capital expenditures and $34 million for maintenance capital during 2012. 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 $1.42 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.
Year Ended December 31, 2010
Cash used in investing activities in 2010 of $1.83 billion was comprised primarily of total capital expenditures of $1.51 billion (excluding the allowance for equity funds used during construction). ETP invested $1.29 billion for growth capital expenditures in 2010 (primarily related to the Tiger pipeline) and $99 million for maintenance capital expenditures. Regency invested $152 million for growth capital expenditures and $7 million for maintenance capital expenditures between May 26, 2010 and December 31, 2010. In addition, Regency paid cash for acquisitions of $191 million, ETP paid cash for acquisitions of $178 million, and we received $24 million in cash from the acquisition of Regency. Regency received $70 million in cash for the sale of its East Texas assets. Our subsidiaries made advances to joint ventures of $93 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, 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.

Table of Contents

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.

Year Ended December 31, 2010

Cash provided by financing activities was $761 million in 2010. ETP received $1.15 billion in net proceeds from offerings of ETP Common Units, including $239 million under ETP's equity distribution program. In addition, Regency received $400 million in net proceeds from offerings of Regency Common Units. We had a consolidated net increase in our debt level of $310 million and paid distributions of $483 million to our common unitholders and $14 million to our preferred unitholders. In addition, ETP paid distributions of $476 million on limited partner interests other than those held by the Parent Company, and Regency paid $92 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.

Financing activities in 2010 also include the Parent Company's completion of $1.8 billion of senior notes in September 2010, the proceeds of which were used to repay outstanding indebtedness under existing credit facilities.

Table of Contents

Description of Indebtedness

Our outstanding consolidated indebtedness at December 31, 2012 and 2011 was as follows (in millions):

	December 31, 2012	2011
Parent Company Indebtedness:		
ETE Senior Notes	$1,800	$1,800
ETE Senior Secured Term Loan	2,000	—
ETE Senior Secured Revolving Credit Facility	60	72
Subsidiary Indebtedness:		
ETP Senior Notes	7,692	6,550
Panhandle Senior Notes	1,621	—
Regency Senior Notes	1,962	1,350
Sunoco Senior Notes	965	—
Sunoco Logistics Senior Notes	1,450	—
Southern Union Senior Notes	1,260	—
Transwestern Senior Unsecured Notes	870	870
HOLP Senior Secured Notes	—	71
Credit Facilities:		
ETP Revolving Credit Facility	1,395	314
Regency Revolving Credit Facility	192	332
Southern Union Revolving Credit Facility	210	—
Sunoco Logistics Revolving Credit Facilities	139	—
Other long-term debt	48	11
Unamortized premiums and fair value adjustments, net	389	1
Total debt	22,053	11,371
Less: current maturities	(613)	(424)
Long-term debt, less current maturities	$21,440	$10,947

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

Under the Parent Company Credit Agreement, the obligations of ETE are secured by all tangible and intangible assets of ETE and certain of its subsidiaries, including (i) its ownership of 50,226,967 ETP Common Units; (ii) ETE's 100% equity interest in ETP LLC and ETP GP, through which ETE holds the IDRs in ETP; (iii) the 26,266,791 common units of Regency; and (iv) ETE's 100% equity interest in Regency GP LLC and Regency GP LP, through which ETE holds the IDRs in Regency.

Borrowings bear interest, at ETE's option, at either the Eurodollar rate plus an applicable margin or the alternative base rate. The alternative base rate used to calculate interest on base rate loans will be calculated using the greater of a prime rate, a federal funds effective rate plus 0.50%, and an adjusted one-month LIBOR rate plus 1.00%. The applicable margins are based upon ETE's leverage ratio and range from 2.75% to 3.75% for Eurodollar loans and from 1.75% to 2.75% for base rate loans. The commitment fee payable on the unused portion of the Parent Company Credit Agreement is based on ETE's leverage ratio and ranges from 0.50% to 0.75%.

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

As of December 31, 2012, we had a balance of $60 million outstanding under the Parent Company Credit Agreement and the amount available for future borrowings was $140 million. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 4.06%.
We issued a $2.0 billion Senior Secured Term Loan as permanent financing to fund the cash portion of the Southern Union Merger and pay related fees and expenses, including existing borrowings under our revolving credit facility and for general partnership purposes.
ETP January 2013 Senior Notes Offering
In January 2013, ETP completed a public offering of $800 million aggregate principal amount of its 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 approximately $1.24 billion from this offering to repay borrowings outstanding under its revolving credit facility and for general partnership purposes.
Sunoco Logistics 2012 Senior Notes Offering
In addition, in January 2013, Sunoco Logistics issued $350 million of 3.45% Senior Notes and $350 million of 4.95% Senior Notes (the “2023 and 2043 Senior Notes”), due January 2023 and January 2043, respectively. The terms and conditions of the 2023 and 2043 Senior Notes are comparable to those under Sunoco Logistics' existing Senior Notes. The net proceeds of $691 million were used to pay outstanding borrowings under the $350 million and $200 million Credit Facilities and for general partnership purposes.
ETP Credit Facility
The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2016. 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.
As of December 31, 2012, ETP had a balance of $1.40 billion outstanding under the ETP Credit Facility and, taking into account letters of credit of approximately $72 million, $1.03 billion available for future borrowings. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 1.71%.
Regency Revolving Credit Facility
The Regency Credit Facility has aggregate revolving commitments of $1.15 billion, with $200 million of availability for letters of credit. Regency also has the option to request an additional $250 million in revolving commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the credit facility have been met. The maturity date of the Regency Credit Facility is June 15, 2014.
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 1.50% to 2.25% for base rate loans and 2.50% to 3.25% for Eurodollar loans. Regency pays (i) a commitment fee ranging between 0.375% and 0.50% 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 2.50% and 3.25% 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 0.125% 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.

Table of Contents

As of December 31, 2012, Regency had a balance outstanding of $192 million under the Regency Credit Facility in revolving credit loans and approximately $12 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2012, which is reduced by any letters of credit, was approximately $946 million. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 2.93%.

Southern Union Credit Facilities

The Southern Union Credit Facility provides for borrowings of up to $700 million and expires in May 2016. Borrowings on the Southern Union Credit Facility are available for working capital, other general company purposes and letter of credit requirements. The interest rate and commitment fee under the Southern Union Credit Facility are calculated using a pricing grid, which is based on the credit ratings for Southern Union's senior unsecured notes. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 1.84%.

On August 10, 2012, Southern Union entered into a First Amendment of the Southern Union Credit Facility. The amendment provides for, among other things, (i) a revision to the change of control definition to permit equity ownership of Southern Union by ETP or any direct subsidiaries of ETP in addition to ETE or any direct or indirect subsidiary of ETE; and (ii) a waiver of any potential default that may result from the Holdco Transaction.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains two credit facilities to fund its working capital requirements, finance acquisitions and capital projects and for general partnership purposes. The credit facilities consist of a $350 million unsecured credit facility which expires in August 2016 (the “$350 million Credit Facility”) and a $200 million unsecured credit facility which expires in August 2013 (the “$200 million Credit Facility”). Outstanding borrowings under these credit facilities were $93 million and $26 million, respectively, at December 31, 2012.

In May 2012, West Texas Gulf entered into a $35 million revolving credit facility (the “$35 million 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 $20 million at December 31, 2012.

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The Parent Company Credit Agreement contains customary representations, warranties and covenants, including financial covenants regarding a maximum leverage ratio, a maximum consolidated leverage ratio, a minimum fixed charge coverage ratio and a minimum loan to value ratio. In addition, the Parent Company Credit Agreement contains customary events of default, including, but not limited to, (i) default for failure to pay the principal on any loan or any reimbursement obligation with respect to any letter of credit when due and payable, (ii) failure to duly observe, perform or comply with certain specified covenants, (iii) a representation or warranty made in connection with any loan document proves to have been false or incorrect in any material respect on any date on or as of which made, and (iv) the occurrence of a change of control.

The Parent Company Senior Secured Revolving Credit Facility contains financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to Consolidated EBITDA (as defined in the agreements) of the Parent Company of not more than 4.5 to 1, with a permitted increase to 5 to 1 during a specified acquisition period extending for two fiscal quarters following the close of a specified acquisition;
- Maximum Consolidated Leverage Ratio – Consolidated Funded Debt of the Parent Company, ETP and Regency to Consolidated EBITDA of ETP and Regency of not more than 5.5 to 1;
- Fixed Charge Coverage Ratio of not less than 3 to 1; and
- Value to Loan Ratio of not less than 2 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

Table of Contents

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 5.25 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 2.75 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 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;

Table of Contents

- 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. Under the current credit agreements, the financial covenants are as follows:

- Under the Southern Union Credit Facility, the ratio of consolidated funded debt to consolidated earnings before interest, taxes, depreciation and amortization, as defined therein, cannot exceed 5.25% through December 31, 2012 and 5.00 times thereafter;
- Under the Southern Union Credit Facility, in the event Southern Union's credit rating falls below investment grade, the ratio of consolidated earnings before interest, taxes, depreciation and amortization to consolidated interest expense, as defined therein, cannot be less than 2.00 times;
- Under LNG Holding's $455 million term loan, the ratio of consolidated funded debt to consolidated earnings before interest, taxes, depreciation and amortization, as defined therein, for Panhandle cannot exceed 5.00.

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 Credit Agreements

The $350 and $200 million Sunoco Logistics Credit Facilities contain various covenants limiting the Sunoco Logistics' 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 Sunoco Logistics' subsidiaries. The credit facilities also limit the 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.

In connection with the acquisition of Sunoco by ETP in October 2012, Sunoco’s interests in the general partner and limited partnership were contributed to ETP, resulting in a change of control of the Sunoco Logistics' general partner. This would have represented an event of default under the Sunoco Logistics' credit facilities as the general partner interests would no longer be owned by Sunoco. During the third quarter 2012, Sunoco Logistics amended this provision of its credit facilities to avoid an event of default upon the transfer of the general partner interest to ETP.

95

Table of Contents

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, 2012 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.

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, 2012.

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 ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt, as defined in the CRSA.

Table of Contents

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2012, excluding amounts related to our held for sale operations, (in millions):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
Long-term debt	$21,667	$613	$2,543	$5,257	$13,254
Interest on long-term debt [a]	13,547	1,236	2,268	1,951	8,092
Payments on derivatives	168	90	71	—	7
Purchase commitments [b]	63,822	12,575	14,711	13,705	22,831
Transportation, natural gas storage and fractionation contracts	431	56	130	119	126
Lease obligations	831	92	160	116	463
Distributions and Redemption of Preferred Units [c]	278	42	16	16	204
Other	272	75	86	40	71
Totals [d]	$101,016	$14,779	$19,985	$21,204	$45,048

(a) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2012. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2012. 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.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for 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, 2012 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 $61 billion of total purchase commitments related to production from PES.

(c) Assumes the Preferred Units are converted to ETE Common Units on May 26, 2014 and assumes the Regency Preferred Units are redeemed for cash on September 2, 2029.

(d) Excludes net non-current deferred tax liabilities of $3.57 billion due to uncertainty of the timing of future cash flows for such liabilities.

Table of Contents

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	Distribution per ETE Common Unit
September 30, 2012	November 6, 2012	November 16, 2012	$0.6250
June 30, 2012	August 6, 2012	August 17, 2012	0.6250
March 31, 2012	May 4, 2012	May 18, 2012	0.6250
December 31, 2011	February 7, 2012	February 17, 2012	0.6250
September 30, 2011	November 4, 2011	November 18, 2011	$0.6250
June 30, 2011	August 5, 2011	August 19, 2011	0.6250
March 31, 2011	May 6, 2011	May 19, 2011	0.5600
December 31, 2010	February 7, 2011	February 18, 2011	0.5400
September 30, 2010	November 8, 2010	November 19, 2010	$0.5400
June 30, 2010	August 9, 2010	August 19, 2010	0.5400
March 31, 2010	May 7, 2010	May 19, 2010	0.5400
December 31, 2009	February 8, 2010	February 19, 2010	0.5400

On January 28, 2013, the Parent Company declared a cash distribution for the three months ended December 31, 2012 of $0.635 per Common Unit, or $2.54 annualized. We paid this distribution on February 19, 2013 to Unitholders of record at the close of business on February 7, 2013.

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 (in millions):

	Years Ended December 31,		
	2012	2011	2010
Limited Partners	$703	$543	$482
General Partner interest	1	2	1
Total Parent Company distributions	$704	$545	$483

Table of Contents

Cash Distributions Received by the Parent Company

We currently have no independent operations outside of our direct and indirect interests in ETP, Holdco and Regency. The Parent Company’s only cash-generating assets currently consist of distributions from ETP, Holdco and Regency related to the following limited and general partner interests, including IDRs:

- ETE’s ownership of the general partner interest in ETP, which it holds through its ownership interests in ETP GP.
- 50,226,967 ETP Common Units, which ETE holds directly, representing approximately 15% of the total outstanding ETP Common Units as of December 31, 2012.
- 100% of the IDRs in ETP, which we hold through our ownership interest in ETP GP and which entitle us to receive specified percentages of the cash distributed by ETP as ETP’s per unit distribution increases. The IDRs held by ETP GP entitles it to receive an increasing share of ETP’s cash distributions when pre-defined distribution targets are achieved. The IDRs in ETP entitle us to receive 48% of ETP’s cash distributions in excess of $0.4125 per unit.
- ETE’s ownership of the general partner interest in Regency, which it holds through it ownership interest in Regency GP.
- 26,266,791 Regency Common Units, which ETE holds directly, representing approximately 15% of the total outstanding Regency Common Units as of December 31, 2012.
- 100% of the IDRs in Regency, which we hold through our ownership interest in Regency GP and which entitle us to receive the specified percentages of the cash distributed by Regency as Regency’s per unit distribution increases. The IDRs held by Regency GP entitles it to receive an increasing share of cash distributions when pre-defined distribution targets are achieved. Regency’s partnership agreement, which IDRs entitle the Parent Company to receive 13% of Regency’s cash distributions after each unitholder receives a total of $0.4025 per unit and until $0.4375 per unit, 23% of Regency’s cash distributions after each Regency Unitholder receives a total of $0.4375 per unit and until $0.525 per unit and 48% of Regency’s cash distributions in excess of $0.525 per unit.
- 60% equity interest in Holdco.

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

	Years Ended December 31,		
	2012	2011	2010
Distributions from ETP:			
Limited Partners	$180	$180	$191
General Partner Interest	20	20	20
Incentive Distribution Rights	439	422	376
Total distributions from ETP	639	622	587
Distributions from Regency:			
Limited Partners	48	48	35
General Partner Interest	5	5	4
Incentive Distribution Rights	8	6	3
Total distributions from Regency	61	59	42
Distributions from Holdco	75	—	—
Total distributions from subsidiaries	$775	$681	$629

Table of Contents

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:

Quarter Ended	Record Date	Payment Date	Distribution per ETP Common Unit
September 30, 2012	November 6, 2012	November 14, 2012	$0.89375
June 30, 2012	August 6, 2012	August 14, 2012	0.89375
March 31, 2012	May 4, 2012	May 15, 2012	0.89375
December 31, 2011	February 7, 2012	February 14, 2012	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	$0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
December 31, 2010	February 7, 2011	February 14, 2011	0.89375
September 30, 2010	November 8, 2010	November 15, 2010	$0.89375
June 30, 2010	August 9, 2010	August 16, 2010	0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375
December 31, 2009	February 8, 2010	February 15, 2010	0.89375

On January 28, 2013, ETP declared a cash distribution for the three months ended December 31, 2012 of $0.89375 per ETP Common Unit, or $3.575 annualized. ETP paid this distribution on February 14, 2013 to ETP Unitholders of record at the close of business on February 7, 2013.

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,		
	2012	2011	2010
Limited Partners:			
Common Units	$963	$762	$677
Class E Units [(1)]	12	12	12
Class F Units [(1)]	170	—	—
General Partner interest	20	20	20
Incentive Distribution Rights	439	422	376
Total ETP distributions	$1,604	$1,216	$1,085

[(1)] All of the outstanding Class E Units and Class F Units are held by subsidiaries of Holdco, which is 60% owned by ETE subsequent to October 5, 2012.

Table of Contents

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	Distribution per Regency Common Unit
September 30, 2012	November 6, 2012	November 14, 2012	$0.46
June 30, 2012	August 6, 2012	August 14, 2012	0.46
March 31, 2012	May 7, 2012	May 14, 2012	0.46
December 31, 2011	February 6, 2012	February 13, 2012	0.46
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
September 30, 2010	November 5, 2010	November 12, 2010	$0.445
June 30, 2010	August 6, 2010	August 13, 2010	0.445

On January 28, 2013, Regency declared a cash distribution for the three months ended December 31, 2012 of $0.46 per Regency Common Unit, or $1.84 annualized. Regency paid this distribution on February 14, 2013 to Regency Unitholders of record at the close of business on February 7, 2013.

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 (in millions):

	Years Ended December 31,	
	2012	2011
Limited Partners	$314	$275
General Partner Interest	5	5
Incentive Distribution Rights	8	6
Total Regency distributions	$327	$286

New Accounting Standards

None.

Table of Contents

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 segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2012 represent the actual results in all material respects.

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

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

Our intrastate transportation and storage and interstate transportation segments' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. Excess fuel retained after consumption is typically valued at market prices.

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

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural
gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

Table of Contents

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot prices and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

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

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

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

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

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

If 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 was based predominantly on an income approach model and is also considered Level 3. 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

Table of Contents

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 and propane supply, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other midstream companies, including major energy producers. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity to 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 3 to 83 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful lives of our property, plant and equipment.

Asset Retirement Obligation.   We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. 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, 2012 and 2011 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, 2012, there were no legally restricted funds for the purpose of settling AROs.

Pensions and Other Postretirement Benefit Plans

The Partnership is required to measure plan assets and benefit obligations as of its fiscal year-end balance sheet date. The Partnership recognizes the changes in the funded status of its defined benefit postretirement plans through AOCI.

Table of Contents

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 the Citigroup Pension Discount Curve as published on the Society of Actuaries website as the 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 of this report.
Environmental Remediation Activities. Sunoco’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 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 also reflected in the accruals to the extent they are probable of occurrence and reasonably estimable.
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. Sunoco’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, 2012, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $200 million. This estimate of reasonably possible losses associated with environmental remediation is largely based upon analysis during 2012 and continuing into early 2013 of the potential liabilities associated with the establishment of the segregated environmental fund discussed above. It also includes estimates for remediation activities at current logistics and retail assets. This reasonably possible loss estimate 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 Sunoco’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 none of the current remediation locations, which are in various stages of ongoing remediation, is individually material to Sunoco as its largest accrual for any one Superfund site, operable unit or remediation area was approximately $28 million at December 31, 2012. As a result, Sunoco’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 Sunoco facilities, formerly owned facilities

Table of Contents

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 Company'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 $270 million have been included in ETE's consolidated balance sheet as of December 31, 2012. All of the deferred income tax assets except $3 million attributable to state and federal NOL benefits expiring before 2032 as more fully described below and the federal alternative minimum tax credits are attributable to the acquisitions of Southern Union and Sunoco. The state NOL carryforward benefits of $104 million begin to expire in 2013 with a substantial portion expiring between 2029 and 2032. The federal NOLs benefits of $129 million expire between 2030 and 2032, while the $37 million of the federal tax alternative minimum tax credit carryforwards have no expiration date. We have determined that a valuation allowance totaling $90 million (net of federal income tax effects) is required for the state NOLs at December 31, 2012 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. We also have determined that a valuation allowance of $4 million is required for federal net operating loss carryforwards. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend "believe," "may," "will" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are 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;

Table of Contents

- 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Table of Contents

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity variations, risk and interest rate variations, and to a lesser extent, credit risks. From time to time, we may utilize derivative financial instruments as described below to manage our exposure to such risks.

Commodity Price Risk

The tables below summarize commodity-related financial derivative instruments, fair values and the effect of an assumed hypothetical 10% change in the underlying price of the commodity as of December 31, 2012 and 2011 for ETP and Regency, including derivatives related to their respective subsidiaries.

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

Our consolidated balance sheets also reflect assets and liabilities related to commodity derivatives that have previously been de-designated as cash flow hedges or for which offsetting positions have been entered. Those amounts are not subject to change based on changes in prices.

Table of Contents

ETP

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

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling forward financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention natural gas in excess of consumption, a portion of volumes purchased at the wellhead from producers, and location price differentials related to the transportation of natural gas. Additionally, we use derivatives for trading purposes in this segment.
- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We also use derivative swap contracts to mitigate risk from price fluctuations on NGLs we retain for fees in our midstream segment.
- Our propane segment permitted customers to guarantee the propane delivery price for the next heating season. We executed fixed sales price contracts with our customers and entered into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. We used propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.
- In our Other segment, we utilized derivatives for trading purpose, primarily in the electricity markets.

The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

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

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in cost of products sold in our consolidated statements of operations.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. Changes in the spreads between the forward natural gas prices designated as fair value hedges and the physical Bammel inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized.

We attempt to maintain balanced positions to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Table of Contents

Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power, gallons for propane and barrels for NGLs and refined products. Dollar amounts are presented in millions.

	December 31, 2012			December 31, 2011		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX(1)	(30,980,000)	$(6)	$—	(151,260,000)	$(23)	$3
Power:						
Forwards	19,650	—	1	—	—	—
Futures	(1,509,300)	(1)	1			
Options — Calls	1,656,400	2	1	—	—	—
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	150,000	(1)	—	(61,420,000)	4	—
Swing Swaps IFERC	(83,292,500)	1	1	92,370,000	(1)	—
Fixed Swaps/Futures	27,077,500	(7)	9	797,500	(4)	—
Forward Physical Contracts	11,689,855	—	2	(10,672,028)	—	1
NGLs:						
Forwards/Swaps	(30,000)	—	—	—	—	—
Refined Products	(666,000)	(3)	14	—	—	—
Propane:						
Forwards/Swaps	—	—	—	38,766,000	(4)	5
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(18,655,000)	(1)	—	(28,752,500)	(1)	—
Fixed Swaps/Futures	(44,272,500)	4	15	(45,822,500)	71	14
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Fixed Swaps/Futures	(8,212,500)	(3)	3	—	—	—
Options — Puts	—	—	—	3,600,000	6	1
Options — Calls	—	—	—	(3,600,000)	—	—
NGLs:						
Forwards/Swaps	(930,000)	(2)	7	—	—	—
Refined Products	(98,000)	—	1	—	—	—

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

111

Table of Contents

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.

Notional volumes are presented in MMBtu for natural gas, gallons for propane and barrels for NGLs and WTI crude oil. Dollar amounts are presented in millions.

	December 31, 2012			December 31, 2011		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives (Non-Trading)						
Natural Gas:						
Fixed Swaps/Futures	8,395,000	$1	$3	—	$—	$—
Propane:						
Forwards/Swaps	3,318,000	1	1	—	—	—
NGLs:						
Forwards/Swaps	243,000	—	2	—	—	—
Options — Puts	—	—	—	110,000	—	—
WTI Crude Oil:						
Forwards/Swaps	356,000	2	3	—	—	—
Cash Flow Hedging Derivatives (Non-Trading)						
Natural Gas:						
Fixed Swaps/Futures	—	—	—	2,198,000	4	1
Propane:						
Forwards/Swaps	—	—	—	11,802,000	(2)	2
NGLs:						
Forwards/Swaps	—	—	—	533,000	(6)	3
WTI Crude Oil:						
Forwards/Swaps	—	—	—	350,000	(1)	3

Regency, for accounting purposes, de-designated its swap contracts on January 1, 2012 and is accounting for these contracts using mark-to-market accounting.

Table of Contents

Interest Rate Risk

As of December 31, 2012, ETP had $2.20 billion of floating rate debt outstanding, Regency had $192 million of floating rate debt outstanding under its revolving credit facilities and ETE had $2.06 billion of floating rate debt outstanding under its revolving credit facilities as of December 31, 2012. A hypothetical change of 100 basis points would result in a change to interest expense of $45 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

The following interest rate swaps were outstanding as of December 31, 2012 and 2011 (dollars in millions), none of which are designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2012	December 31, 2011
ETE	March 2017	Pay a fixed rate of 1.25% and receive a floating rate	$500	$—
ETP	May 2012 [2]	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	—	350
ETP	August 2012 [2]	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	—	500
ETP	July 2013 [2]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	400	300
ETP	July 2014 [2]	Forward starting to pay a fixed rate of 4.25% and receive a floating rate	400	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	500
Regency	April 2012	Pay a fixed rate of 1.325% and receive a floating rate	—	250
Southern Union	November 2016	Pay a fixed rate of 2.91% and receive a floating rate	75	N/A
Southern Union	November 2021	Pay a fixed rate of 3.75% and receive a floating rate	450	N/A

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

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

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a change in the fair value of the interest rate derivatives and earnings (recognized in losses on non-hedged interest rate derivatives) of approximately $118 million as of December 31, 2012. For ETP’s $600 million of interest rate swaps whereby it pays a floating rate and receives a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flow (swap settlements) of $6 million. For Southern Union's fixed to floating interest rate swaps, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows (swap settlements) of $7 million.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties’ financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposures associated with a single or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrial, small to major oil and gas producers, midstream and power generation companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

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.

Table of Contents

Certain of Southern Union's derivative instruments contain provisions that require Southern Union's debt to be maintained at an investment grade credit rating from each of the major credit rating agencies. If Southern Union's debt were to fall below investment grade, Southern Union would be in violation of these provisions, and the counterparties to the derivative instruments could potentially require Southern Union to post collateral for certain of the derivative instruments.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the President and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the President and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2012.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Equity, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the President and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco. Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity. Management has acknowledged that it is responsible for establishing and maintaining a system of internal controls over financial reporting for Sunoco. We are in the process of integrating Sunoco, and we therefore excluded Sunoco from our December 31, 2012 assessment of the effectiveness of internal control over financial reporting. Sunoco had total assets of $4.51 billion at December 31, 2012 and third party revenue of $5.93 billion from October 5, 2012 to December 31, 2012 included in our consolidated financial statements as of and for the year ended December 31, 2012. The impact of the Sunoco transaction has not materially affected and is not expected to materially affect our internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient controls over the substantive results of our financial reporting throughout this integration process.

Our assessment of internal control over financial reporting did include assessments of Sunoco Logistics and Southern Union, both of which ETP obtained control of in connection with the Sunoco Merger and Holdco Transaction.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2012.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2012, as stated in their report, which is included herein.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Equity, L.P.

We have audited the internal control over financial reporting of Energy Transfer Equity, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. Our audit of, and opinion on, the Partnership's internal control over financial reporting does not include the internal control over financial reporting of Sunoco, Inc., a consolidated subsidiary, whose financial statements reflect total assets and revenues constituting 9 and 35 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012. As indicated in Management's Report on Internal Control over Financial Reporting, Sunoco, Inc. was acquired during 2012, and therefore, management's assertion on the effectiveness of the Partnership's internal control over financial reporting excluded internal control over financial reporting of Sunoco, Inc. We did not audit the internal control over financial reporting of Sunoco Logistics Partners L.P., a consolidated subsidiary, whose financial statements as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012 reflect total assets and revenues constituting 21 and 19 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012. Sunoco Logistics Partners L.P.'s internal control over financial reporting was audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to Sunoco Logistics Partners L.P.'s internal control over financial reporting in relation to the Partnership taken as a whole, is based solely on the report of the other auditors.

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

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

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

In our opinion, based on our audit and the report of the other auditors, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2012, and our report dated March 1, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 1, 2013

Table of Contents

Changes in Internal Controls over Financial Reporting

There has been no change in our internal controls over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner, LE GP, LLC, manages and directs all of our activities. The officers and directors of ETE are officers and directors of LE GP, LLC. The members of our General Partner elect our General Partner's Board of Directors. The board of directors of our General Partner has the authority to appoint our executive officers, subject to provisions in the limited liability company agreement of our General Partner. Pursuant to other authority, the board of directors of our General Partner may appoint additional management personnel to assist in the management of our operations and, in the event of the death, resignation or removal of our chief executive officer, to appoint a replacement.

As of December 31, 2012, our Board of Directors was comprised of seven persons, three of whom qualify as "independent" under the NYSE's corporate governance standards. We have determined that Messrs. Harkey, Ramsey and Turner are all "independent" under the NYSE's corporate governance standards.

As a limited partnership, we are not required by the rules of the NYSE to seek unitholder approval for the election of any of our directors. We believe that the members of our General Partner have appointed as directors individuals with experience, skills and qualifications relevant to the business of the Parent Company, such as experience in energy or related industries or with financial markets, expertise in natural gas operations or finance, and a history of service in senior leadership positions. We do not have a formal process for identifying director nominees, nor do we have a formal policy regarding consideration of diversity in identifying director nominees, but we believe that the members of our General Partner have endeavored to assemble a group of individuals with the qualities and attributes required to provide effective oversight of the Parent Company.

Risk Oversight. Our Board of Directors generally administers its risk oversight function through the board as a whole. Our President, who reports to the Board of Directors, has day-to-day risk management responsibilities. Our President attends the meetings of our Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, at each regular meeting of the Board, management provides a report of the Parent Company's financial and operational performance, which often prompts questions or feedback from the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Parent Company's internal auditor, who reports directly to the Audit Committee, and reviews the Parent Company's contingencies with management and our independent auditors.

Corporate Governance

The Board of Directors has adopted both a Code of Business Conduct and Ethics applicable to our directors, officers and employees, and Corporate Governance Guidelines for directors and the Board. Current copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and charters of the Audit and Compensation Committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Unitholder requesting such information.

Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Table of Contents

Annual Certification

The Parent Company has filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 to this annual report. In 2012, our President and CFO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE's corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Parent Company and our Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Parent Company to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Parent Company. Pursuant to the terms of our partnership agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Parent Company, approved by all partners of the Parent Company and not a breach by the General Partner or its Board of Directors of any duties they may owe the Parent Company or the Unitholders.

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407(d)(5) of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee member John D. Harkey, Jr. qualified as an audit committee financial expert during 2012. A description of the qualifications of Mr. Harkey may be found elsewhere in this Item 10 under "Directors and Executive Officers of the General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by auditing standards, and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Audit Committee has received written disclosures and the letter from Grant Thornton required by applicable requirements of the Audit Committee concerning independence and has discussed with Grant Thornton that firm's independence. The Audit Committee recommended to the Board that the audited financial statements of ETE be included in ETE's Annual Report on Form 10-K for the year ended December 31, 2012.

The Board of Directors adopts the charter for the Audit Committee. John D. Harkey, Jr., Matthew S. Ramsey and K. Rick Turner serve as elected members of the Audit Committee. Messr. Ramsey began service on the Audit Committee subsequent upon his appointment to our Board of Directors on July 17, 2012. Mr. Harkey currently serves as the Chair of the Committee. Mr. Harkey currently serves as a member or chairman of the audit committee of three other publicly traded companies, including the general partner of Regency, in addition to his service as a member of the Audit Committee of our General Partner. As required by Rule 303A.07 of the NYSE Listed Company Manual, the Board of Directors of our General Partner has determined that such simultaneous service does not impair Mr. Harkey's ability to effectively serve on our Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of LE GP, LLC has previously established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans, including the performance standards or other restrictions pertaining to the vesting of any such awards. Pursuant to the Charter of the Compensation Committee, a director serving as a member of the Compensation Committee may not be an officer of or employed by our General Partner, the Parent Company, ETP or its subsidiaries, or Regency or its subsidiaries. Subsequent to the resignations of Paul E. Glaske and Bill W. Byrne from the board of directors of our General

Table of Contents

Partner effective June 30, 2011, we do not currently have a compensation committee; therefore, the members of the board of directors of our General Partner who would be eligible to be members of the Compensation Committee currently serve in that capacity.

Matters relating to the nomination of directors or corporate governance matters are addressed to and determined by the full Board of Directors.

In the discussion and analysis that follows, we have used the term, “ETE Compensation Committee,” to refer to either or both of (i) our compensation committee, which existed through June 30, 2011 and (ii) the eligible members of the board of directors of our General Partner, functioning in the capacity of our compensation committee subsequent to June 30, 2011.

The responsibilities of the ETE Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of our President and CFO, if applicable;
- annually evaluate the President and CFO’s performance in light of these goals and objectives, and make recommendations to the board of directors of our General Partner with respect to the President and CFO’s compensation levels, if applicable, based on this evaluation;
- make determinations with respect to the grant of equity-based awards to executive officers under ETE’s equity incentive plans;
- periodically evaluate the terms and administration of ETE’s long-term incentive plans to assure that they are structured and administered in a manner consistent with ETE’s goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, President and CFO or executive officer compensation; and
- perform other duties as deemed appropriate by the board of directors of our General Partner.

The responsibilities of the ETP Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of the Chief Executive Officer, or the CEO, if applicable; annually evaluate the CEO’s performance in light of these goals and objectives, and make recommendations to the board of directors of ETP’s general partner with respect to the CEO’s compensation levels based on this evaluation, if applicable;
- based on input from, and discussion with, the CEO, make recommendations to the board of directors of ETP’s general partner with respect to non-CEO executive officer compensation, including incentive compensation and compensation under equity based plans;
- make determinations with respect to the grant of equity-based awards to executive officers under ETP’s equity incentive plans;
- periodically evaluate the terms and administration of ETP’s short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with ETP’s goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and
- perform other duties as deemed appropriate by the board of directors of ETP’s general partner.

Code of Business Conduct and Ethics

The Board of Directors has adopted a Code of Business Conduct and Ethics applicable to our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. Amendments to, or waivers from, the Code of Business Conduct and Ethics will be available on our website and reported as may be required under SEC rules. Any technical, administrative or other non-substantive amendments to the Code of Business Conduct and Ethics may not be posted.

Table of Contents

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. Our non-management directors alternate as the presiding director of such meetings.

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

Directors and Executive Officers of the General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of March 1, 2013. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Our General Partner
John W. McReynolds	62	Director, President and Chief Financial Officer
Kelcy L. Warren	57	Director and Chairman of the Board
John D. Harkey, Jr.	52	Director
Marshall S. (Mackie) McCrea, III	53	Director
Matthew S. Ramsey	58	Director
K. Rick Turner	55	Director

Messrs. Warren and McCrea also serve as directors of ETP's General Partner. Messrs. McReynolds and Harkey also serve as directors of Regency's General Partner.

Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:

John W. McReynolds. Mr. McReynolds has served as our President since March 2005 and served as a Director and Chief Financial Officer since August 2005. He has previously served as a director of Energy Transfer Partners from August 2001 through May 2010. Mr. McReynolds has also served as a director of Regency since May 2010. Prior to becoming President of Energy Transfer Equity, Mr. McReynolds was a partner with an international law firm for over 20 years. As a lawyer, Mr. McReynolds specialized in energy-related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in special projects for Boards of Directors for public companies. The members of our General Partner selected Mr. McReynolds to serve as a director because of his legal background and his extensive experience in energy-related corporate finance. Mr. McReynolds has relationships with executives and senior management at several companies in the energy sector, as well as with investment bankers who cover the industry.

Kelcy L. Warren. Mr. Warren was appointed Co-Chairman of the Board of Directors of our General Partner, LE GP, LLC, effective upon the closing of our IPO. On August 15, 2007, Mr. Warren became the sole Chairman of the Board of our General Partner and the Chief Executive Officer and Chairman of the Board of the General Partner of ETP. Prior to that, Mr. Warren had served as Co-Chief Executive Officer and Co-Chairman of the Board of the General Partner of ETP since the combination of the midstream and intrastate transportation storage operations of Energy Transfer Company ("ETC OLP") and the retail propane operations of Heritage in January 2004. Mr. Warren also serves as Chief Executive Officer of the General Partner of ETC OLP. Prior to the combination of the operations of ETP and Heritage Propane, Mr. Warren served as President of the General Partner of ET Company I, Ltd. the entity that operated ETP's midstream assets before it acquired Aquila, Inc.'s midstream assets, having served in that capacity since 1996. From 1996 to 2000, he also served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 25 years of business experience in the energy industry. The members of our General Partner selected Mr. Warren to serve as a director and as Chairman because he is ETP's Chief Executive Officer and has more than 25 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.

John D. Harkey, Jr. Mr. Harkey has served as Chief Executive Officer and Chairman of Consolidated Restaurant Companies, Inc., since 1998. Mr. Harkey currently serves on the Board of Directors of Leap Wireless International, Inc., Loral Space & Communications, Inc., Emisphere Technologies, Inc., and the Board of Directors for the Baylor Health Care System Foundation. He currently serves on the Audit Committees of Loral. He also serves on the President's Development Council of Howard Payne

Table of Contents

University and on the Executive Board of Circle Ten Council of the Boy Scouts of America. In May 2010, Mr. Harkey was elected Chairman of the Board of Directors of Regency's General Partner and member of the Audit Committee. In May 2006, Mr. Harkey was elected as a director of our General Partner and member of the Audit Committee. He currently serves as the Chairman of the Audit Committee of our General Partner. The members of our General Partner selected Mr. Harkey to serve as a director because of his background in corporate finance, as well as his experience as a director on the boards and audit committees of several other public companies.

Marshall S. (Mackie) McCrea, III. Mr. McCrea was appointed as a director on December 23, 2009. He is the President and Chief Operating Officer of ETP GP and has served in that capacity since June 2008. Prior to that, he served as President – Midstream from March 2007 to June 2008. Previously he served as the Senior Vice President – Commercial Development since the combination of the operations of ETC OLP and HOLP in January 2004. In March 2005, Mr. McCrea was named president of ETC OLP. Prior to the combination of the operations of ETC OLP and HOLP, Mr. McCrea served as the Senior Vice President – Business Development and Producer Services of the general partner of ETC OLP and ET Company I, Ltd., having served in that capacity since 1997. Mr. McCrea also currently serves on the Board of Directors of the general partner of ETE and of Sunoco Logistics. The members of our General Partner selected Mr. McCrea to serve as a director because he brings extensive project development and operations experience to the Board. He has held various positions in the natural gas business over the past 25 years and is able to assist the Board of Directors in creating and executing the Partnership's strategic plan.

Matthew S. Ramsey. Mr. Ramsey was appointed as a director on July 17, 2012. Mr. Ramsey is presently President of RPM Exploration, Ltd., a private oil and gas exploration partnership generating and drilling 3-D seismic prospects on the Gulf Coast of Texas. Mr. Ramsey is also President of Ramsey Energy Management, LLC, the General Partner of Ramsey Energy Partners, I, Ltd., a private oil and gas partnership and as President of Dollarhide Management, LLC, the General Partner of Deerwood Investments, Ltd., a private oil and gas partnership. Additionally, Mr. Ramsey is President of Gateshead Oil, LLC, a private oil and gas partnership. Prior to that, Mr. Ramsey served as President of DDD Energy, Inc. until its sale in 2002. From 1996 to 2000, Mr. Ramsey served as President and Chief Executive Officer of OEC Compression Corporation, Inc., a publicly traded oil field service company, providing gas compression services to a variety of energy clients. Previously, Mr. Ramsey served as Vice President of Nuevo Energy Company, an independent energy company. Additionally, he was employed by Torch Energy Advisors, Inc., a company providing management and operations services to energy companies including Nuevo Energy, last serving as Executive Vice President. Mr. Ramsey joined Torch Energy as Vice President of Land and was named Senior Vice President of Land in 1992. Prior to joining Torch Energy Advisors, Inc., Mr. Ramsey was self employed for eleven years. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of Harvard Business School Advanced Management Program. He is licensed to practice law in the State of Texas. He is qualified to practice in the Western District of Texas and the United States Court of Appeals for the Fifth Circuit.

K. Rick Turner. Mr. Turner is a private equity executive with several groups after having recently retired from the Stephens' family entities, which he had worked for since 1983. He first became a private equity principal in 1990 after serving as the Assistant to the Chairman, Jackson T. Stephens. His areas of focus have been oil and gas exploration, natural gas gathering, processing industries, and power technology. Prior to joining Stephens, he was employed by Peat, Marwick, Mitchell and Company. Mr. Turner currently serves as a director of North American Energy Partners Inc., AmeriGas and PMI, LLC. Mr. Turner has served as a director of our General Partner since October 2002. Mr. Turner earned his B.S.B.A. from the University of Arkansas and is a non-practicing Certified Public Accountant. The members of our General Partners selected Mr. Turner based on his industry knowledge, his background in corporate finance and accounting, and his experience as a director and audit committee member on the boards of several other companies.

Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Parent Company.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership and changes in beneficial ownership with the SEC. Officers, directors and greater than 10% Unitholders are required by SEC regulations to furnish the General Partner with copies of all Section 16(a) forms.

Based solely on our review of the copies of such forms received by us, or written representations from certain reporting persons that no Forms 5 were required for those persons, we believe that for our year ended December 31, 2012, all filing requirements applicable to its officers, directors, and greater than 10% beneficial owners were met in a timely manner.

Table of Contents

ITEM 11. EXECUTIVE COMPENSATION

Overview

Since we are a limited partnership, we are managed by our General Partner. Our General Partner is majority owned by Mr. Kelcy Warren. Our limited partner interests are owned approximately 25% by affiliates and approximately 75% by the public.

We own 100% of ETP GP and its general partner, ETP LLC. We refer to ETP GP and ETP LLC together as the "ETP GP Entities." ETP GP is the general partner of ETP. All of ETP's employees receive employee benefits from the operating companies of ETP.

We own 100% of Regency GP and its general partner, Regency LLC. We refer to Regency GP LP and Regency GP LLC together as the "Regency GP Entities." Regency GP is the general partner of Regency. All of Regency's employees receive employee benefits from the operating companies of Regency.

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the President of our General Partner performs all of our management functions. The compensation of our President is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the President of our General Partner. In addition, to provide comprehensive disclosure of our executive compensation, we are also providing information as to the executive compensation of the ETP GP Entities, since the shared service agreement with ETP may place ETP's executives in a position to perform policy making functions for ETE from time to time, even though none of these persons is an executive officer of the Parent Company. Accordingly, the persons we refer to in this discussion as our "named executive officers" are the following:

ETE Executive Officer

- John W. McReynolds, President and Chief Financial Officer of our General Partner.

ETP GP Entities Executive Officers

- Kelcy L. Warren, Chief Executive Officer;
- Marshall S. (Mackie) McCrea, III, President and Chief Operating Officer;
- Martin Salinas, Jr., Chief Financial Officer;
- Thomas P. Mason, Senior Vice President, General Counsel and Secretary; and
- Richard Cargile, President of Midstream Operations.

Our Philosophy for Compensation of Executives

Our General Partner. In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based and that executives' base salary levels should be competitive in the marketplace for executive talent and abilities. Our General Partner also believes the incentives should be competitive in the marketplace and balanced between short and long-term performance. Our General Partner believes this balance is achieved by the payment of annual discretionary cash bonuses and grants of restricted unit awards. Our General Partner believes the performance of our operating subsidiaries and the contribution of our management toward the achievement of the financial targets and other goals of those subsidiaries should be considered in determining annual discretionary cash bonuses.

ETP GP Entities. The ETP GP Entities also believe that a significant portion of each executives' compensation should be incentive-based and that executives' base salary levels should be competitive in the marketplace for executive talents and abilities. ETP GP also believes the incentives should be competitive in the marketplace and balanced between short and long-term performance. ETP GP believes this balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of ETP's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of its named executive officers to the success of ETP and (ii) the annual grant of restricted unit awards under ETP's equity incentive plans, which are intended to provide a longer term incentive to its key employees to focus their efforts on increasing the market price of its publicly traded units and to increase the cash distribution ETP pays to its Unitholders. Prior to December 2012, ETP's equity awards were been primarily in the form of restricted unit awards that vest over a specified time period, with substantially all of these types of unit awards vesting over a five-year period at 20% per year based on continued employment through each specified vesting date. Beginning in December 2012, we began granting restricted unit awards that vest, based upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. The ETP GP Entities believe that these equity-based incentive arrangements are important in attracting and retaining executive officers and key employees as well as motivating these individuals to achieve ETP's business objectives. The equity-based compensation reflects the importance ETP GP places on aligning the interests of its named executive officers with those of ETP's Unitholders.

While ETE is responsible for the direct payment of the compensation of our named executive officer as an employee of ETE, ETE does not participate or have any input in any decisions as to the compensation levels or policies of our General Partner, the ETP GP Entities or the Regency GP Entities. As discussed below, our compensation committee or the eligible members of board of directors of our General Partner at times when we have not had a compensation committee, is responsible for the compensation policies and compensation level of the executive officer of our General Partner. In this discussion, we refer to either or both of our compensation committee or such members of our board of directors as the "ETE Compensation Committee."

ETP also does not participate or have any input in any decisions as to the compensation policies of the ETP GP Entities or the compensation levels of the executive officers of the ETP GP Entities. The compensation committee of the board of directors of the ETP GP Entities (the "ETP Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of the executive officers of the ETP GP Entities.

ETE and ETP directly pay their respective executive officers in lieu of receiving an allocation of overhead related to executive compensation from their respective general partner. For the year ended December 31, 2012, ETE and ETP paid 100% of the compensation of the executive officers of their respective general partner as each entity represents the only business currently managed by such general partner.

For a more detailed description of the compensation to ETE's and ETP GP's named executive officers, please see "–Compensation Tables" below.

Distributions to Our General Partner

Our General Partner is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our partnership agreement with respect to its ownership of its general partner interest as specified in our partnership agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our partnership agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officer. Distributions to our General Partner are described in detail in Note 8 to our consolidated financial statements. Our named executive officer also owns directly and indirectly certain of our limited partner interests and, accordingly, receives quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officer.

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

Compensation Philosophy

Each of ETE's and ETP's compensation programs are structured to provide the following benefits:

- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2012, the compensation paid to ETE's named executive officer consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses; and

- equity incentive plan compensation.

Table of Contents

Mr. Warren, ETP's CEO, has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits). The compensation paid to the named executive officers of the ETP GP Entities, other than ETP's CEO, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of cash bonuses;
- vesting of previously issued equity-based awards issued pursuant to ETP's equity incentive plans;
- compensation resulting from the vesting of equity awards made by an affiliate; and
- 401(k) plan contributions.

Methodology

Presently, the compensation committees of ETE and ETP consider relevant data available to them to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officer. The boards of directors and compensation committees of ETE and ETP also consider individual performance, levels of responsibility, skills and experience.

Periodically, the ETP Compensation Committee engages a third-party consultant to provide master information for compensation levels at peer companies in order to assist the ETP Compensation Committee in its determination of compensation levels for ETP's executive officers. Most recently, the ETP Compensation Committee engaged Mercer Consulting Services ("Mercer") during the year ended December 31, 2010 to assist in the determination of ETP's compensation levels for its senior management. The results of this study were utilized to determine long-term incentive awards and bonuses during 2012, 2011 and 2010. The consultant provided an analysis of compensation for senior executives of the following 15 companies in the energy industry, comprised primarily of midstream and exploration and production companies:

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

The compensation analysis provided by Mercer covered annual salary, annual cash bonus and long-term incentive arrangements for the senior executives of these companies. The ETP Compensation Committee utilized the information provided by Mercer to compare the levels of base salary, annual bonus and long-term equity incentives at these other companies with those of ETP's named executive officers to ensure that compensation of ETP's named executive officers is competitive with the compensation for executive officers of these other companies. The ETP Compensation Committee did not attempt to benchmark the base salary, annual bonus or long-term equity incentives to any percentage of, or numerical average of, the compensation levels at these other companies. Mercer did not provide any non-executive compensation services for ETP during 2012, 2011 or 2010.

The ETE Compensation Committee has not engaged a compensation consultant during the periods presented herein.

Base Salary. For the year ended December 31, 2012, the base salary level, equity incentive compensation and the non-equity incentive compensation of Mr. McReynolds, the President and Chief Financial Officer of ETE's General Partner, was determined by the board of directors of our General Partner based on recommendations from the ETE Compensation Committee after taking into account the compensation for senior executives at comparable companies with respect to annual salary, annual cash bonus and long-term incentive arrangements, and the total compensation for similarly situated senior executives at ETP. The ETE Compensation Committee did not increase Mr. McReynolds' base salary for 2012.

The base salaries of ETP's named executive officers are determined by ETP's board of directors based on recommendations from the ETP Compensation Committee, which take into account the recommendations of Mr. Warren. For 2012, the ETP Compensation Committee approved an increase of 19% to Mr. McCrea's annual base salary, 18% to Mr. Salinas' annual base salary, and 16% to Mr. Mason's annual base salary. The ETP Compensation Committee determined that such increases were warranted based on the factors described below under "– Annual Bonus." The ETP Compensation Committee also deemed the increases to be reasonable in light of the expanded roles that each of the individuals serves with respect to the consolidated organization subsequent to the Citrus, Sunoco, and Holdco transactions in 2012. The ETP Compensation Committee did not increase the base salary of Mr. Cargile given his employment with the Partnership began in 2012.

Annual Bonus. In January 2013, the ETE Compensation Committee approved a cash bonus relating to the 2012 calendar year to Mr. McReynolds in the amount of $522,500. In approving this cash bonus, the ETE Compensation Committee took into account the significant role that Mr. McReynolds played in negotiating and coordinating the successful consummation of the Southern Union Merger, as well as his role in multiple other transactions among ETE and its subsidiaries. The ETE Compensation Committee also took into account the individual performance of Mr. McReynolds with respect to promoting ETE’s financial, strategic and operating objectives for 2012.

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

ETP’s internal financial budgets are generally developed for each of its operations, and then aggregated with appropriate corporate level adjustments to reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all operations of ETP’s business. The evaluation of ETP’s performance versus its internal financial budget is based on the Partnership’s EBITDA for a calendar year. In general, the ETP Compensation Committee believes that ETP’s performance at or above the internal EBITDA budget would support bonuses to named executive officers of the ETP GP Entities ranging from 100% to 120% of their annual salary. The individual bonus amounts for each named executive officer of the ETP GP Entities, other than ETP’s CEO, also reflect the ETP Compensation Committee’s view of the impact of such individual’s efforts and contributions towards (i) achievement of ETP’s success in exceeding its internal financial budget, (ii)the development of new projects that are expected to result in increased cash flows from operations in future years, (iii) the completion of mergers, acquisitions or similar transactions that are expected to be accretive to the Partnership and increase distributable cash flow, and (iv) the overall management of ETP’s business.

In February 2013, the Compensation Committee approved cash bonuses relating to the 2012 calendar year to Messrs. McCrea, Salinas, Mason and Cargile of $700,000, $375,000, $500,000 and $230,000, respectively. In approving the cash bonuses for Messrs. McCrea, Salinas, Mason and Cargile, the Compensation Committee took into account the achievement by the Partnership of approximately 95% of its internal EBITDA budget of $2.75 billion for 2012 as well as the individual performances of these individuals with respect to promoting the Partnership's financial, strategic and operating objectives for 2012. The cash bonuses for Messrs. Salinas and Cargile were consistent with the target. Mr. McCrea and Mr. Mason's cash bonuses exceeded target amounts by 7% and 13%, respectively. With respect to Mr. McCrea, the Compensation Committee noted his leadership in the successful development of several significant internal growth projects, including (i) the early completion of Lone Star's West Texas Gateway NGL pipeline with estimated capital expenditures of approximately $917 million, (ii) the completion of Lone Star's first NGL fractionation facility at Mont Belvieu, Texas with estimated capital expenditures of $390 million and the negotiation of multiple long-term agreements to support Lone Star's planned construction of a second fractionation facility, (iii) the negotiation of long-term commitments from producers to support the planned further expansion of our REM pipeline project and the construction of a new processing facility in the Eagle Ford Shale in South Texas that was placed in service in December 2012. In addition, the Compensation Committee recognized the increased scope of Mr.

McCrea's responsibilities following the acquisitions of Southern Union and Sunoco in 2012. With respect to Mr. Mason, the Compensation Committee took note of his key roles in (i) successfully consummating the acquisition by ETE of Southern Union and ETP's acquisition of a 50% interest in Citrus Corp., (ii) effectively negotiating and consummating the merger of Sunoco and ETP and the related contribution by ETE of its interest in Southern Union, and by ETP of its interest in Sunoco, to ETP Holdco, (iii) overseeing the successful negotiation of agreements to sell Southern Union's Missouri Gas Energy and New England Gas Company divisions to the Laclede Entities for $1.035 billion and (iv) effectively managing of the legal functions for ETE and ETP, as well as Southern Union and Sunoco as part of the ongoing integration of those companies into Energy Transfer.

ETE Equity Awards. The Energy Transfer Equity Long-Term Incentive Plan authorizes the ETE Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other awards related to ETE units at such times and upon such terms and conditions as it may determine in accordance with each such plan. The ETE Compensation Committee determined and/or approved the terms of the unit grants awarded to the named executive officer of ETE, including the number of ETE Common Units subject to the unit award and the vesting structure of those unit awards. All of the awards granted to the named executive officer under this equity incentive plan have consisted of restricted unit awards, which are subject to vesting over a specified time period. ETE Common Units are issued upon grant of the award, subject to forfeiture of unvested units upon termination of employment during the vesting period.

The ETE Compensation Committee has not yet determined what equity awards will be made to Mr. McReynolds for 2012.

The issuance of ETE Common Units pursuant to ETE's equity incentive plan is intended to serve as a means of incentive compensation; therefore, no consideration will be payable by the plan participants upon vesting and issuance of the ETE Common Units.

ETP Equity Awards. Each of ETP's 2004 Unit Plan and 2008 Incentive Plan authorizes the ETP Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other awards related to ETP units at such times and upon such terms and conditions as it may determine in accordance with each such plan. The ETP Compensation Committee determined and/or approved the terms of the unit grants awarded to the named executive officers of the ETP GP Entities, including the number of Common Units subject to the unit award and the vesting structure of those unit awards. All of the awards granted to ETP's named executive officers under these equity incentive plans have consisted of restricted unit awards, which have required the achievement of certain performance objectives in order for the awards to become vested or restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any unit award, ETP Common Units are issued.

Commencing in 2008, all of the new ETP unit awards granted have provided for vesting over a specified time period, with vesting based on continued employment as of each applicable vesting date, rather than vesting based on the satisfaction of any performance objectives. This change resulted from the Compensation Committee's determination that vesting based on continued employment, rather than the satisfaction of performance objectives, was more generally prevalent with companies in the energy industry. In January 2013, the ETP Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas, Mason and Cargile of 33,333 units, 16,667 units, 30,000 units and 12,000 units, respectively. These unit awards provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, subject to continued employment though each specific vesting date. Upon inception of his employment in March 2012, Mr. Cargile also received a grant of 18,000 units which vest ratably over five years.

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 ETP Common Units promptly following each such distribution by ETP to its Unitholders. In approving the grant of such unit awards, the ETP Compensation Committee took into account the same factors as discussed above under the caption "Annual Bonus," the long-term objective of retaining such individuals as key drivers of the Partner's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity unit awards subject to vesting.

In approving the grant of such unit awards, the ETP Compensation Committee took into account the same factors as discussed above under the caption "Annual Bonus," the long-term objective of retaining such individuals as key drivers of ETP's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity unit awards subject to vesting.

The issuance of ETP Common Units pursuant to ETP's equity incentive plans is intended to serve as a means of incentive compensation; therefore, no consideration will be payable by the plan participants upon vesting and issuance of the ETP Common Units.

The unit awards under ETP's equity incentive plans generally require the continued employment of the recipient during the vesting period. The ETP Compensation Committee has in the past and may in the future, but is not required to, accelerate the vesting of unvested unit awards in the event of the termination or retirement of an executive officer. The ETP Compensation Committee did not accelerate the vesting of unit awards to any named executive officers in 2012.

Subsidiary Equity Awards. In addition to their roles as officers of our General Partner, Messrs. Salinas and McCrea also serve as officers and directors of the general partner of Sunoco Logistics. In connection with those roles at Sunoco Logistics' general partner, in January 2013, the compensation committee of Sunoco Logistics' general partner awarded Messrs. Salinas and McCrea time-based restricted units of Sunoco Logistics in the amount of 8,333 units and 16,667 units, respectively. These awards provide for vesting over a five-year vesting period at a rate of 20% per year, subject to continued employment. These awards have not been reflected in the compensation tables presented below, because the grant date occurred subsequent to December 31, 2012.

Table of Contents

Affiliate Equity Awards. McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of our General Partner, has voluntarily elected to award to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such partnership. These rights include the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETE or ETP unless this partnership defaults under its obligations under these unit awards once they are granted. We are recognizing non-cash compensation expense over the vesting period based on the grant date fair value of the ETE units awarded the ETP employees assuming no forfeitures.

Messrs. McCrea and Salinas vested in rights related to ETE units of 42,000 and 48,000, respectively, during 2012. Messrs. McCrea and Salinas had unvested rights related to ETE units of 42,000 and 48,000, respectively, as of December 31, 2012. The time restrictions related to these remaining unvested rights will lapse in 2013.

Qualified Retirement Plan Benefits. We have established a defined contribution 401(k) plan, which covers substantially all employees of ETE and ETP, including named executive officers. Employees may elect to their up to 100% of defined eligible compensation after applicable taxes, as limited under the Internal Revenue Code. We make a matching contribution that is not less than the aggregate amount of matching contributions that would be credited to a participant's account based on a rate of match equal to 100% of each participant's elective deferrals up to 5% of covered compensation. The entire amount credited to the participant's account is fully vested and non-forfeitable at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

Health and Welfare Benefits. All full-time employees, including our and ETP's named executive officers, may participate in our health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance and disability insurance.

Termination Benefits. ETE's and ETP's named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner. Each of ETE's and ETP's long-term incentive plans provides for immediate vesting of all unvested unit awards in the event of a change of control, as defined in the respective plan. Please refer to "– Compensation Tables – Potential Payments Upon a Termination or Change of Control" for additional information.

Deferred Compensation Plan. ETE does not have a deferred compensation plan. Effective January 1, 2010, ETP adopted a deferred compensation plan ("DC Plan"), which permits eligible highly compensated ETP employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other designated distribution. Under the DC Plan, each year eligible ETP employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, ETP may make annual discretionary matching contributions to participants' accounts; however, ETP has not made any discretionary contributions to participants' accounts and currently has no plans to make any discretionary contributions to participants' accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings (or losses) based on hypothetical investment fund choices made by the participants among available funds.

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

Risk Assessment Related to our Compensation Structure. We believe that the compensation plans and programs for named executive officers of ETE and ETP, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to ETE or ETP. We believe these compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm the value of ETE or ETP or reward poor judgment. We also believe ETE and ETP have allocated compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, ETE and ETP generally do not adjust base annual salaries for executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of a portion of our operations. ETE and ETP generally determine whether, and to what extent, their respective named executive officers receive a cash bonus based on achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership's success. ETE and ETP use restricted units rather than unit options for equity awards because restricted units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options "in-the-money." Finally, the time-based vesting over five years for ETE's and ETP's long-term incentive awards ensures that the interests of employees align with those of the respective unitholders of ETE and ETP for the long-term performance of ETE and ETP.

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officer is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

For unit-based compensation arrangements, including equity-based awards issued to certain of ETP's named executive officers by Mr. McReynolds (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 9 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

During 2012, matters concerning Mr. McReynolds's compensation were deliberated by the members of the board of directors of our General Partner who would be eligible to serve on the ETE Compensation Committee, which consisted of Messrs. Harkey, Ramsey and Turner, as well as former board members, Mr. Ray C. Davis and Mr. David R. Albin. Messrs. Ramsey and Albin participated in such deliberations during the portion of 2012 for which they served on the board. During that time, none of Messrs. Harkey, Ramsey, Turner, Davis or Albin was an officer or employee of ETE or any of its subsidiaries or served as an officer of any company with respect to which any of ETE's executive officers served on such company's board of directors. Mr. Davis, who resigned from the board of directors of our General Partner in February 2013, formerly served as Co-Chief Executive Officer and Co-Chairman of the board of directors of the General Partner of ETP until 2007.

In February 2013, Messrs. Harkey and Ramsey were appointed to the Compensation Committee.

Report of Compensation Committee

The board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of ETE. Based on this review and discussion, we have recommended that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the
Board of Directors of LE GP, LLC,
general partner of Energy Transfer Equity, L.P.

John D. Harkey, Jr.
Matthew S. Ramsey

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

Table of Contents

Compensation Tables
Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Equity Awards ($) (2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
ETE Officer:									
John W. McReynolds	2012	$550,000	$522,500	$ —	$ —	$ —	$ —	$ 13,834	$1,086,334
President and Chief	2011	550,000	550,000	—	—	—	—	12,795	1,112,795
Financial Officer	2010	550,000	550,000	995,500	—	—	—	8,462	2,103,962
ETP Officers:									
Kelcy L. Warren [4]	2012	3,398	—	—	—	—	—	—	3,398
Chief Executive	2011	3,240	—	—	—	—	—	—	3,240
Officer	2010	2,766	—	—	—	—	—	—	2,766
Martin Salinas, Jr.	2012	425,000	375,000	755,515			23,261	26,140	1,604,916
Chief Financial	2011	360,532	400,000	1,128,500	—	—	(6,462)	25,020	1,907,590
Officer	2010	356,058	480,000	999,600	—	—	7,648	27,250	1,870,556
Marshall S. (Mackie) McCrea, III	2012	750,000	700,000	1,510,985	—	—	—	12,802	2,973,787
President and Chief	2011	615,049	750,000	9,542,520	—	—	—	12,972	10,920,541
Operating Officer	2010	538,077	729,500	13,455,000	—	—	—	12,250	14,734,827
Thomas P. Mason	2012	500,000	500,000	1,359,900	—	—	—	35,998	2,395,898
Senior Vice	2011	432,901	750,000	1,805,600	—	—	—	32,590	3,021,091
President, General Counsel and Secretary	2010	427,513	482,530	999,600	—	—	—	34,990	1,944,633
Richard Cargile President of Midstream Operations	2012	237,500	230,000	1,379,880	—	—	3,534	12,279	1,863,193

(1) The discretionary cash bonus amounts for named executive officers for 2012 reflect cash bonuses approved by the ETE and ETP Compensation Committees in February 2013 that are expected to be paid in March 2013.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. See Note 9 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2012 in this column include (i) contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $10,067 and $11,875 for Messrs. Salinas and Cargile, respectively, and $12,250 each for Messrs. McCrea and Mason, (ii) expenses paid by us for housing for Messrs. Salinas and Mason near our executive office in Dallas and (iii) the dollar value of life insurance premiums paid for the benefit of the named executive officers. Vesting in 401(k) contributions occurs immediately.

(4)

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

Table of Contents

Grants of Plan-Based Awards Table

Name	Grant Date	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Sh)	Grant Date Fair Value of Unit Awards (1)
ETE Officer:					
John W. McReynolds	N/A	—	—	$—	$—
ETP Officers:					
Kelcy L. Warren	N/A	—	—	—	—
Martin Salinas, Jr.	1/10/2013	16,667	—	—	755,515
Marshall S. (Mackie) McCrea, III	1/10/2013	33,333	—	—	1,510,985
Thomas P. Mason	1/10/2013	30,000	—	—	1,359,900
Richard Cargile	1/10/2013	12,000	—	—	543,960
	3/14/2012	18,000	—	—	835,920

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 9 to our consolidated financial statements.

We do not have any non-equity incentive plans.

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

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

Table of Contents

Outstanding Equity Awards at Year-End Table

Name	Grant Date (1)	Unit Awards Equity Incentive Plan Awards: Number of Units That Have Not Vested (#) (1)	Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested ($) (2)
ETE Officer:			
John W. McReynolds	2/24/2011	20,000	$ 909,600
	12/29/2009	12,000	545,760
	12/19/2008	10,000	454,800
ETP Officers:			
Kelcy L. Warren	N/A	—	—
Martin Salinas, Jr.	1/10/2013	16,667	715,514
	12/20/2011	20,000	858,600
	12/15/2010	12,000	515,160
	12/15/2009	7,674	329,445
	12/22/2008	4,000	171,720
Marshall S. (Mackie) McCrea, III	1/10/2013	33,333	1,430,986
	12/20/2011	40,000	1,717,200
	5/2/2011	81,600	3,503,088
	1/14/2011	150,000	6,439,500
	12/15/2009	8,000	343,440
	12/22/2008	4,000	171,720
Thomas P. Mason	1/10/2013	30,000	1,287,900
	12/20/2011	32,000	1,373,760
	12/15/2010	12,000	515,160
	12/15/2009	7,274	312,273
	12/22/2008	4,000	171,720
	10/17/2008	10,000	429,300
Richard Cargile	1/10/2013	12,000	515,160
	3/14/2012	14,400	618,192

(1) Unit awards outstanding to Mr. McReynolds in December of each year through 2015 for awards granted in 2011, through 2014 for awards granted in 2009 and through 2013 for awards granted in 2008. Unit awards outstanding to Messrs. Salinas, McCrea, Mason and Cargile vest as follows:

- At a rate of 60% in December 2015 and 40% in December 2017 for awards granted in January 2013;
- Ratably in December of each year through 2016 for awards granted in December 2011 and March 2012;
- Ratably in December of each ear through 2015 for awards granted in December 2010, January 2011 and May 2011;
- Ratably in December of each year through 2014 for awards granted in December 2009;
- In December 2013 for awards granted in December 2008; and
- In October 2013 for awards granted in October 2008.

(2) Market value was computed as the number of unvested awards as of December 31, 2012 multiplied by the closing price of ETP’s Common Units for ETP officers and ETE’s Common Units for the ETE officer on December 31, 2012.

The amounts above do not include the equity awards granted to certain of ETP's named executive officers in equity of ETE held by a partnership controlled by Mr. McReynolds. These awards are not issued pursuant to any of ETE's or ETP's equity incentive plans, and such awards are voluntarily made in the sole discretion of Mr. McReynolds.

Table of Contents

Option Exercises and Units Vested Table

Name	Unit Awards Number of Units Acquired on Vesting (#) (1)	Value Realized on Vesting ($) (1)
ETE Officer:		
John W. McReynolds	16,000	$955,080
ETP Officers:		
Kelcy L. Warren	—	—
Martin Salinas, Jr.	18,038	780,107
Marshall S. (Mackie) McCrea, III	99,600	4,307,501
Thomas P. Mason	33,238	1,433,267
Richard Cargile	3,600	155,693

(1) Amounts presented represent the number of unit awards vested during 2012 and the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the applicable closing market price per unit upon the vesting date.

We have not issued option awards.

Nonqualified Deferred Compensation Table

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance At December 31, 2011 ($)
ETE Officer:					
John W. McReynolds	$—	$—	$—	$—	$—
ETP Officers:					
Kelcy L. Warren	—	—	—	—	—
Martin Salinas, Jr.	25,926	—	23,261	—	202,849
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Richard Cargile	97,338	—	3,534	—	100,872

The aggregate earnings reflected above for Mr. Salinas and Mr. Cargile are included in total compensation in the "Summary Compensation Table."

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

Potential Payments Upon a Termination or Change of Control

Equity Awards. As discussed in our Compensation Discussion and Analysis above, any unvested equity awards granted pursuant to ETP's 2004 Unit Plan will automatically become vested upon a change of control. Assuming that a change of control occurred on December 31, 2012, the fair value of the unvested awards granted pursuant to ETP's 2004 Unit Plan as of December 31, 2012 were $171,720 for Mr. Salinas, $171,720 for Mr. McCrea and $1,116,180 for Mr. Mason, respectively. In addition, Messrs. Salinas and McCrea hold unvested rights to receive ETE units granted by McReynolds Energy Partners, L.P. that would become immediately vested in connection with a change in control. Assuming that a change of control occurred on December 31, 2012, the fair value of these awards would have been $2,183,040 for Mr. Salinas and $1,910,160 for Mr. McCrea. Although any unvested equity awards granted under the 2008 Incentive Plan may also become vested upon a change of control at the discretion of the Compensation Committee, this discussion assumes a scenario in which the Compensation Committee does not exercise such discretion.

While any individual award agreement may contain a modified definition, a change of control is generally defined under the 2004 Unit Plan as the occurrence of any of the following events: (i) ETP GP ceases to be our general partner; (ii) ETE ceases to own, directly or indirectly through wholly-owned subsidiaries, in the aggregate at least 51% of the capital stock or equity interests of ETP GP; (iii) the sale of all or substantially all of ETP's assets (other than to any affiliate of ETE); or (iv) a liquidation or dissolution of ETP. For purposes of the rights with respect to ETE units granted by McReynolds Energy Partners, L.P., a change in control means a "change in control" as defined in the 2004 Unit Plan, but a change in control will also be considered to have occurred if any single party, other than Kelcy Warren, acquires either: (a) more than 90% of the then-outstanding limited partner units of ETE; or (b) more than 51% of the ownership of LE GP, LLC. Under the 2008 Incentive Plan, a "change of control" is generally defined as the occurrence of one or more of the following events: (1) any person or group becomes the beneficial owner of 50% or more of our voting power or voting securities; (2) the complete liquidation of either ETP LLC, ETP GP, or us; (3) the sale of all or substantially all of ETP GP's or our assets to anyone other than us, ETP GP or one of our affiliates; or (4) a person other than ETP LLC, ETP GP or one of their affiliates becomes our general partner.

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

Director Compensation

Directors of LE GP, LLC who are employees of the LE GP, LLC, ETP GP or any of their subsidiaries are not eligible for director compensation. The compensation arrangements for outside directors include a $30,000 annual retainer for services on the board and an annual retainer ($5,000 or $7,500 in the case of the chairman) and meeting attendance fees ($1,200) for services on the Audit Committee. Beginning in 2013, the compensation arrangements for outside directors include a $50,000 annual retainer for services on the board and an annual retainer ($10,000 or $15,000 in the case of the chairman) and meeting attendance fees ($1,200) for services on the Audit Committee. In connection with the Sunoco Acquisition and Holdco Transaction, the Board of LE GP, LLC appointed a special committee consisting of Messrs. Davis, Harkey and Turner (the "ETE Special Committee") and conflicts committee consisting of Mr. Turner (the "ETE Conflicts Committee"). For their service, the ETE Special Committee members received a fee of $25,000, and the sole member of the ETE Conflicts Committee received an additional $5,000 fee. Beginning in 2013, members of the Special Committee or Conflicts Committee will receive a flat fee cash payment of $5,000 for each matter referred to such committee.

The outside directors of LE GP, LLC are also entitled to an annual award under the Energy Transfer Equity, L.P. Long-Term Incentive Plan equal to $15,000 divided by (a) the closing price of the Common Units of ETE on the New York Stock Exchange on such grant-date or (b) the Fair Market Value of a common unit as otherwise determined by the Board of Directors. Each award is subject to a restricted period of three (3) years and vests 1/3 per year beginning on the first anniversary date of the award, provided that all unvested awards fully vest upon the occurrence of a change of control. The compensation expense recorded is based on the grant-date market value of the ETE Common Units and is recognized over the vesting period. Distributions are paid during the vesting period.

Beginning in 2013, outside directors of LE GP, LLC will receive annual grants of restricted ETE Common Units equal to an aggregate of $100,000 divided by the closing price of ETE Common Units on the date of grant. These ETE Common Units will vest 60% after the third year and 40% after the fifth year after the grant date.

The ETP Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of ETP's General Partner. In 2012, non-employee directors of ETP's General Partner received an annual fee of $40,000 plus $1,200 for each committee meeting attended. Beginning in 2013, non-employee directors will receive an annual fee of $50,000 in cash. Additionally, the Chairman of ETP's audit committee receives an annual fee of $15,000 and the members of ETP's Audit Committee receive an annual fee of $10,000. The Chairman of the ETP Compensation Committee receives an annual fee of $7,500 and the members of the ETP Compensation Committee receive an annual fee of $5,000. In connection with the Citrus Acquisition and Sunoco Acquisition, the ETP Conflicts Committee met 27 times to address potential conflicts of interest in the transaction. For their service the, ETP Conflicts Committee members received additional compensation of $2,500 per Conflicts Committee meeting for the members of the Conflicts Committee. Beginning in 2013, members of the ETP Conflicts Committee will receive cash payments on a to-be-determined basis for each ETP Conflicts Committee assignment. ETP's employee directors, including Messrs. Warren and McCrea, do not receive any fees for service as directors. In addition, the non-employee directors participate in ETP's 2004 Unit Plan and 2008 Incentive Plan. Each director of ETP's General Partner who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP

LLC, ETP, or a subsidiary, who is elected or appointed to the board of ETP’s General Partner for the first time shall automatically receive, on the date of his or her election or appointment, an award of 2,500 ETP Common Units. For 2012, under ETP’s 2004 Unit Plan and 2008 Incentive Plan, the non-employee directors of ETP’s General Partner each received annual grants of restricted ETP Common Units equal to an aggregate of $50,000 divided by the closing price of ETP’s Common Units on the date of grant. These ETP Common Units vest over three years at one-third per year. Beginning in 2013, non-employee ETP directors receive annual grants of restricted ETP Common Units equal to an aggregate of $100,000 divided by the closing price of ETP's Common Units on the date of grant. These ETP Common Units will vest 60% after the third year and 40% after the fifth year after the grant date.

Table of Contents

The following table reflects compensation paid during 2012 to the non-employee directors of our General Partner.
Director Compensation Table

Name	Fees Paid in Cash ($) (1)	Unit Awards ($) (2)	All Other Compensation ($)	Total ($)
David R. Albin	34,125	—	—	$34,125
Ray C. Davis [(3)]	55,000	—	—	55,000
John D. Harkey, Jr.				—
As ETE director	74,600	14,999	—	89,599
As Regency director	51,500	—	—	51,500
Matthew S. Ramsey	11,775	—	—	11,775
K. Rick Turner	77,100	14,999	—	92,099

(1) Fees paid in cash for ETE Directors are based on amounts earned during the period. Mr. Albin resigned June 1, 2012, therefore, his fees do not reflect a full year.

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price as of the grant date. For ETP unit awards, the grant date market price is reduced by the expected distributions during the vesting period to determine the grant date fair value. As of December 31, 2012, Messrs. Harkey and Turner each had 786 unvested ETE restricted units outstanding. As of December 31, 2012, Mr. Harkey had 10,068 unvested Regency restricted units outstanding.

(3) Mr. Davis resigned from the Board of Directors of our General Partner effective February 13, 2012

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

At the time of our initial public offering, we adopted the Energy Transfer Equity, L.P. Long-Term Incentive Plan for the employees, directors and consultants of our General Partner and its affiliates who perform services for us. The long-term incentive plan provides for the following five types of awards: restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The long-term incentive plan limits the number of units that may be delivered pursuant to awards to three million units. Units withheld to satisfy exercise prices or tax withholding obligations are available for delivery pursuant to other awards. The plan is administered by the compensation committee of the board of directors of our General Partner.

The following table sets forth in tabular format, a summary of our equity plan information as of December 31, 2012:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	—	$—	—
Equity compensation plans not approved by security holders	—	$—	2,852,936
Total	—	$—	2,852,936

Table of Contents

Energy Transfer Equity, L.P. Units

The following table sets forth certain information as of February 19, 2013, regarding the beneficial ownership of our securities by certain beneficial owners, each director and named executive officer of our General Partner and all directors and executive officers of our General Partner as a group. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Title of Class	Name and Address of Beneficial Owner (1)	Beneficially Owned (2)	Percent of Class	
Common Units	Kelcy L. Warren (7)	44,992,555	16.1	%
	John W. McReynolds (6)	6,567,649	2.3	%
	John D. Harkey, Jr. (5)	43,266	*	
	Marshall S. (Mackie) McCrea, III	1,049,628	*	
	Matthew S. Ramsey	8,279	*	
	K. Rick Turner	83,715	*	
	All Directors and Executive Officers as a group (6 persons)	69,547,567	18.8	%
	Ray C. Davis (4)	16,802,475	6.0	%
	Kayne Anderson Capital Advisors, L.P. (3)	19,111,371	6.8	%

*Less than 1%

(1) The address for Messrs. Warren, McReynolds, Davis, Harkey, McCrea, Ramsey and Turner is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Kayne Anderson Capital Advisors, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(2) Beneficial ownership for the purposes of the foregoing table is defined by Rule 13d-3 under the Exchange Act. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers within sixty days. Nature of beneficial ownership is direct with sole investment and disposition power unless otherwise noted.

(3) The reported units are owned by investment accounts (investment limited partnerships, a registered investment company and institutional accounts) managed, with discretion to purchase or sell securities, by Kayne Anderson Capital Advisors, L.P., as a registered investment advisor, as reported by it on a Schedule 13G. Kayne Anderson Capital Advisors, L.P. is the general partner (or general partner of the general partner) of the limited partnerships and investment adviser to the other accounts. Richard A. Kayne is the controlling shareholder of the corporate owner of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. Mr. Kayne is also a limited partner of each of the limited partnerships and a shareholder of the registered investment company. Kayne Anderson Capital Advisors, L.P. disclaims beneficial ownership of the units reported, except those units attributable to it by virtue of its general partner interests in the limited partnerships. Mr. Kayne disclaims beneficial ownership of the units reported, except those units held by him or attributable to him by virtue of his limited partnership interests in the limited partnerships, his indirect interest in the interest of Kayne Anderson Capital Advisors, L.P. in the limited partnership, and his ownership of the common stock of the registered investment company.

(4) Mr. Davis was formerly a member of the Board of Directors of our General Partner until his resignation effective February 13, 2013. Includes 741,654 units held by Avatar Investments, L.P., 10,423 units held by Avatar Holdings, LLC, 3,223,005 units held by Mr. Davis as Trustee of a trust for the benefit of his spouse, 1,410,522 units held by Mr. Davis's spouse, 5,685,670 units held by Avatar ETC Stock Holdings LLC and 2,175,844 units held by the 2008 Grandchildren's Trusts established by Mr. Davis and his spouse. Also includes 10,066 units held by ETC Holdings, L.P. (over which Mr. Davis exercises shared voting and dispositive power with Mr. Warren). ET GP LLC is the sole general partner of ETC Holdings, L.P. and therefore may be deemed to be beneficially own units held by ETC Holdings, L.P. Excludes an additional 17,964,706 units held by ETC Holdings L.P. in which

Mr. Davis has no ownership interest (see note 7 below).

(5) Includes 15,000 units held by the Katemcy Trust.

(6) Includes 3,940,279 units held by McReynolds Energy Partners L.P. and 2,521,570 units held by McReynolds Equity Partners L.P., the general partners of which are owned by Mr. McReynolds. Mr. McReynolds disclaims beneficial ownership of units owned by such limited partnerships other than to the extent of his interest in such entity.

Table of Contents

(7) Includes 19,175,550 units held by Kelcy Warren Partners, L.P. and 1,739,975 units held by Kelcy Warren Partners II, L.P., the general partners of which are owned by Mr. Warren. Also includes 17,964,706 units held by ETC Holdings L.P. (over which Mr. Warren exercises shared voting and dispositive power with Mr. Davis). ET GP LLC is the sole general partner of ETC Holdings, L.P. and therefore may be deemed to be beneficially own units held by ETC Holdings, L.P. Excludes an additional 10,066 units held by ETC Holdings L.P. in which Mr. Warren has no ownership interest (see note 4 above). Also includes 150,269 units held by LE GP, LLC. Mr. Warren may be deemed to own units held by LE GP, LLC due to his ownership of 81.2% of its member interests. The voting and disposition of these units is directly controlled by the board of directors of LE GP, LLC. Mr. Warren disclaims beneficial ownership of units owned by LE GP, LLC other than to the extent of his interest in such entity.

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

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

The Parent Company's cash flows currently consist of distributions from ETP, Regency and Holdco related to the following interests:

- our ownership of the general partner interest in ETP, which we hold through our ownership interests in ETP GP;
- 50.2 million ETP Common Units, representing approximately 17% of the total outstanding ETP Common Units, which we hold directly;
- 100% of the IDRs in ETP, which we likewise hold through our ownership interests in ETP GP and which entitle us to receive specified percentages of the cash distributed by ETP as ETP's per unit distribution increases;
- our ownership of the general partner interest in Regency, which we hold through our ownership interests in Regency GP;
- 26.3 million Regency Common Units, representing approximately 15% of the total outstanding Regency Common Units;
- 100% of the IDRs in Regency, which we likewise hold through our ownership interests in Regency GP and which entitle us to receive specified percentages of the cash distributed by Regency as Regency's per unit distribution increases; and
- 60% equity interest in Holdco, which directly owns Southern Union and Sunoco.

ETP and Regency are required by their respective partnership agreements to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by the board of directors of their respective general partners.

Immediately following the closing of the Partnership's acquisition of Sunoco, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, the Partnership contributed its interest in Sunoco to Holdco and retained a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to the Partnership in exchange for 90,706,000 Class F Units representing limited partner interests in ETP.

Mr. McCrea, a current director of LE GP, LLC, our General Partner, is also a director and executive officer of ETP GP. In addition, Mr. Warren, the Chairman of our Board of Directors, is also a director and executive officer of ETP GP.

As a policy matter, our Conflicts Committee generally reviews any proposed related party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership's board of directors makes the determinations as to whether there exists a related party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its fiduciary duties to the Unitholders. The partnership agreement of ETE provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to ETE, approved by all the partners of ETE and not a breach by the General Partner or its Board of Directors of any duties they may owe ETE or the Unitholders.

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

Table of Contents

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.

ETP has an operating lease agreement with Messrs. Davis and Warren, the former owners of ETG, which ETP acquired in 2009. Prior to the consummation of the transaction, the committee made the determination that both the sale of ETG to ETP and the terms of the operating lease between ETP and Messrs. Davis and Warren were fair and reasonable to ETP. See discussion in Note 14 to our consolidated financial statements.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following sets forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered:

	Years Ended December 31, 2012	Years Ended December 31, 2011
Audit fees (1)	$5,769,000	$3,138,500
Audit-related fees (2)	25,000	372,000
Tax fees (3)	1,525	9,553
Total	$5,795,525	$3,520,053

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and services related to the audit of our internal controls over financial reporting.

(2) Includes fees in 2012 in connection with the service organization control report on Southern Union's centralized data center. Includes fees in 2011 for attestation engagements of subsidiary entities in connection with the contribution of the Partnership's retail propane operations to AmeriGas Partners, L.P. in January 2012.

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

Pursuant to the charter of the Audit Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee.

The Audit Committee reviews the external auditors’ proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors’ internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two years; and
- the rotation of the lead partner.

PART IV

136

Table of Contents

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this Report:

(1) Financial Statements - see Index to Financial Statements appearing on page F-1.

(2) Financial Statement Schedules - None.

(3) Exhibits - see Index to Exhibits set forth on page E-1.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY TRANSFER EQUITY, L.P.

By: LE GP, LLC,
its general partner

Date: March 1, 2013

By: /s/ John W. McReynolds
John W. McReynolds
President and Chief Financial Officer (duly authorized to sign on behalf of the registrant)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ John W. McReynolds John W. McReynolds	President and Chief Financial Officer (Principal Executive, Financial and Accounting Officer)	March 1, 2013
/s/ Kelcy L. Warren Kelcy L. Warren	Director and Chairman of the Board	March 1, 2013
/s/ John D. Harkey John D. Harkey	Director	March 1, 2013
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	Director	March 1, 2013
/s/ Matthew S. Ramsey Matthew S. Ramsey	Director	March 1, 2013
/s/ K. Rick Turner K. Rick Turner	Director	March 1, 2013

Table of Contents

INDEX TO EXHIBITS

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

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
2.1	1-32740 (8-K/A) (5/13/10)	2.1	General Partner Purchase Agreement, dated May 10, 2010, by and among Regency GP Acquirer, L.P., Energy Transfer Equity, L.P. and ETE GP Acquirer LLC.
2.2	1-32740 (8-K/A) (5/13/10)	2.2	Redemption and Exchange Agreement, dated May 10, 2010, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
2.3	1-32740 (8-K/A) (5/13/10)	2.3	Contribution Agreement, dated May 10, 2010, by and among Energy Transfer Equity, L.P., Regency Energy Partners LP and Regency Midcontinent Express LLC.
2.4	1-32740 (8-K) (6/20/11)	2.1	Agreement and Plan of Merger, by and among, Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and Southern Union Company, dated as of June 15, 2011.
2.5	1-32740 (8-K)(7/5/11)	2.1	Agreement and Plan of Merger, by and among, Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and Southern Union Company, dated as of June 15, 2011, as Amended and Restated as of July 4, 2011.
2.5.1	1-32740 (8-K)(7/5/11)	10.1	Support Agreement dated June 15, 2011 by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and certain stockholders of Southern Union Company.
2.6	1-32740 (8-K)(7/20/11)	2.2	Amended and Restated Agreement and Plan of Merger, by and among, Energy Transfer Partners, L.P., Citrus ETP Acquisition L.L.C., Energy Transfer Equity, L.P., Southern Union Company, and CrossCountry Energy, LLC, dated as of July 19, 2011.
2.7	1-32740 (8-K)(9/15/11)	2.1	Amendment No. 1, dated as of September 14, 2011, to Second Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and Southern Union Company.
2.8	1-32740 (8-K)(9/15/11)	2.2	Amendment No. 1, dated as of September 14, 2011, to Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
2.9	1-32740 (8-K) (3/28/12)	2.1	Amendment No. 2, dated as of March 23, 2012, to Amended and Restated Agreement and Plan of Merger, by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Citrus ETP Acquisition, L.L.C, Southern Union Company and CrossCountry Energy, LLC, dated as of July 19, 2011.
2.10	1-32740 (8-K) (5/1/12)	2.1	Agreement and Plan of Merger, dated as of April 29, 2012 by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc. and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P.

2.11	1-32740 (8-K) (6/20/12)	2.1	Transaction Agreement, dated as of June 15, 2012, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage Holdings, Inc., Energy Transfer Equity, L.P., ETE Sigma Holdco, LLC and ETE Holdco Corporation.
2.12	1-32740 (8-K) (6/20/12)	2.2	Amendment No. 1, dated as of June 15, 2012, to the Agreement and Plan of Merger, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc., and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P.
3.1	333-128097 (S-1) (9/2/05)	3.1	Certificate of Conversion of Energy Transfer Company, L.P.
3.2	333-128097 (S-1) (9/2/05)	3.2	Certificate of Limited Partnership of Energy Transfer Equity, L.P.

Table of Contents

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
3.3	1-32740 (8-K) (2/14/06)	3.1	Third Amended Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.3.1	1-32740 (10-K) (8/31/06)	3.3.1	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.3.2	1-32740 (8-K) (11/13/07)	3.3.2	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.3.3	1-32740 (8-K) (6/2/10)	3.1	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P.
3.4	333-128097 (S-1) (9/2/05)	3.4	Certificate of Conversion of LE GP, LLC.
3.5	333-128097 (S-1) (9/2/05)	3.5	Certificate of Formation of LE GP, LLC.
3.6	1-32740 (8-K) (5/8/07)	3.6.1	Amended and Restated Limited Liability Company Agreement of LE GP, LLC.
3.6.1	1-32740 (8-K) (12/23/09)	3.1	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of LE GP, LLC.
3.7	1-11727 (8-K) (7/28/09)	3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
3.8	1-11727 (10-Q) (2/29/04)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
3.9	1-11727 (10-Q) (5/31/07)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
3.10	1-11727 (10-Q) (5/31/07)	3.6	Third Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C.
3.10.1	1-11727 (8-K) (8/10/10)	3.6	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C.
3.11	333-128097 (S-1/A) (12/20/05)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
3.11.1	333-128097 (S-1/A) (12/20/05)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
3.12	333-128097 (S-1/A) (12/20/05)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
3.13	1-32740 (8-K) (8/10/10)	3.2	Second Amendment to Amended and Restated Limited Liability Company Agreement of Regency GP, L.L.C.
3.14	1-32740 (8-K) (3/28/12)	3.1	Amendment No. 1, dated March 26, 2012, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 28, 2009.
3.15	1-32740 (8-K) (3/28/12)	3.2	Amendment No. 2, dated March 26, 2012, to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated April 17, 2007.
3.16	1-32740 (8-K) (3/28/12)	3.3	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Agreement of Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated August 10, 2010.

4.1	1-11727 (8-K) (1/19/05)	4.1	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
4.2	1-11727 (8-K) (1/19/05)	4.2	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
4.3	1-11727 (10-Q) (2/28/05)	10.45	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005.

Table of Contents

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
4.4	1-11727 (10-Q) (2/28/05)	10.5	Notation of Guaranty.
4.5	1-11727 (8-K) (1/19/05)	4.3	Registration Rights Agreement dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers party thereto.
4.6	1-11727 (10-Q) (2/28/05)	10.39.1	Joinder to Registration Rights Agreement dated February 24, 2005, among Energy Transfer Partners, L.P., the Subsidiary Guarantors and Wachovia Bank, National Association, as trustee.
4.7	1-11727 (8-K) (8/2/05)	4.1	Third Supplemental Indenture dated July 29, 2005, to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein, and Wachovia Bank, National Association, as trustee.
4.8	1-11727 (8-K) (8/2/05)	4.2	Registration Rights Agreement dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein, and the initial purchasers party thereto.
4.9	1-11727 (10-K/A) (8/31/05)	4.9	Form of Senior Indenture of Energy Transfer Partners, L.P.
4.10	1-11727 (10-K/A) (8/31/05)	4.10	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
4.11	1-11727 (10-K) (8/31/06)	4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
4.12	1-11727 (8-K) (10/25/06)	4.1	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
4.13	1-11727 (8-K) (3/28/08)	4.2	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
4.14	1-11727 (8-K) (12/23/08)	4.2	Seventh Supplemental Indenture dated December 23, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
4.15	1-11727 (8-K) (4/7/09)	4.2	Eighth Supplemental Indenture dated April 7, 2009, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
4.16	1-11727 (DEF 14A) (11/21/08)	A	Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan.
4.17	1-32740 (8-K) (6/2/10)	4.14	Registration Rights Agreement by and among Energy Transfer Equity, L.P. and Regency GP Acquirer, L.P., dated as of May 26, 2010.

4.18	1-32740 (8-K) (9/20/10)	4.14	Indenture dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee.
4.19	1-32740 (8-K) (9/20/10)	4.15	First Supplemental Indenture dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes).
4.20	1-32740 (8-K) (2/16/12)	4.1	Second Supplemental Indenture dated as of February 16, 2012, between Energy Transfer Equity, L.P., and U.S. Bank National Association.
4.21	1-32740 (8-K) (9/20/10)	4.1	Third Supplemental Indenture dated April 24, 2012 to Indenture dated September 20, 2010 between Energy Transfer Equity, L.P. and US Bank National Association, as trustee.

Table of Contents

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
10.1	1-11727 (8-K) (2/1/05)	10.1	Purchase and Sale Agreement dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers, and LaGrange Acquisition, L.P., as Buyer.
10.2	1-11727 (8-K) (2/1/05)	10.2	Cushion Gas Litigation Agreement dated January 26, 2005, among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and LaGrange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
10.3	1-11727 (10-K) (8/31/06)	10.45	Energy Transfer Partners, L.P. Summary of Director Compensation.
10.4.1**	1-11727 (10-Q) (6/30/08)	10.6.6	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan.
10.4.2**	1-11727 (8-K) (12/19/08)	10.1	Energy Transfer Partners, L.P. Amended and Restated 2008 Long Term Incentive Plan.
10.4.3**	1-11727 (8-K) (3/31/10)	10.1	Energy Transfer Partners Deferred Compensation Plan.
10.4.4**	1-11727 (8-K) (11/1/04)	10.1	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan.
10.4.5**	1-11727 (8-K) (3/3/2008)	10.1	Energy Transfer Partners, L.P. Midstream Bonus Plan.
10.5	1-11727 (8-K) (2/4/02)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.
10.6	1-11727 (10-Q) (2/29/04)	4.2	Unitholder Rights Agreement dated January 20, 2004, among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and LaGrange Energy, L.P.
10.7	333-128097 (S-1) (333-128097)	10.47	Registration Rights Agreement for Limited Partnership Units of LaGrange Energy, L.P.
10.8**	333-128097 (S-1) (333-128097)	10.25	Energy Transfer Equity, L.P. Long-Term Incentive Plan.
10.9**	333-128097 (S-1) (333-128097)	10.26	Form of Director and Officer Indemnification Agreement.
10.10	1-11727 (8-K) (11/2/11)	10.1	Second Amended and Restated Credit Agreement, dated October 27, 2011, among Energy Transfer Partners, L.P., the borrower, and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents, and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC, as senior managing agents, and other lenders party hereto.

E-4

Table of Contents

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
10.11	1-32740 (8-K) (7/19/06)	10.2	Amended and Restated Credit Agreement dated July 13, 2006, between Energy Transfer Equity, L.P. and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A. and Citicorp North America, Inc., as co-syndication agents, BNP Paribas and The Royal Bank of Scotland plc, as co-documentation agents, Credit Suisse Cayman Islands Branch, Deutsche Bank AG New York Branch and UBS Securities LLC, as senior managing agents, and Fortis Capital Corp, Suntrust Bank and Wells Fargo Bank, N.A., as managing agents.
10.12	1-32740 (10-K) (8/31/06)	10.34	First Amendment to Amended and Restated Credit Agreement, dated November 1, 2006, among Energy Transfer Equity, L.P., as the borrower, Wachovia Bank, National Association as administrative agent, UBS Loan Finance LLC, as syndication agent, BNP Paribas, Citicorp North America, Inc. and JPMorgan Chase Bank, N.A. as co-documentation agents, and UBS Securities LLC and Wachovia Capital Markets, LLC, as joint lead arrangers and joint book managers.
10.12.1	1-32740 (8-K) (6/2/10)	10.1	Second Amended and Restated Credit Agreement, dated as of May 19, 2010, among Energy Transfer Equity, L.P. as the borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A. and Citicorp North America, Inc., as co-syndication agents, BNP PARIBAS and the Royal Bank of Scotland plc, as co-documentation agents, Credit Suisse, Cayman Islands Branch, Deutsche Bank AG New York Branch, and UBS Securities LLC, as senior managing agents, Fortis Capital Corp, and Sun Trust Banks, as managing agents, and other lenders party thereto.
10.13	1-32740 (10-K) (8/31/06)	10.35	Contribution and Conveyance Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P., and Energy Transfer Partners, L.P.
10.14	1-32740 (10-K) (8/31/06)	10.36	Contribution, Assumption and Conveyance Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P., and Energy Transfer Investments, L.P.
10.15	1-11727 (8-K) (11/3/06)	3.1.10	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
10.16	1-32740 (10-K) (8/31/06)	10.38	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P. and Energy Transfer Investments, L.P.
10.17	1-11727 (8-K) (9/18/06)	10.1	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.) Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holding I LLC.

10.18	1-11727 (8-K) (9/18/06)	10.2	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
10.19	1-11727 (8-K) (9/18/06)	10.3	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
10.20	1-32740 (8-K)(11/30/06)	99.1	Registration Rights Agreement, dated November 27, 2006, by and among Energy Transfer Equity, L.P. and certain investors named therein.
10.21**	1-32740 (8-K)(12/26/06)	99.1	LE GP, LLC Outside Director Compensation Policy.
10.22	1-32740 (8-K)(3/5/07)	99.1	Registration Rights Agreement, dated March 2, 2007, by and among Energy Transfer Equity, L.P. and certain investors named therein.
10.23	1-32740 (8-K)(5/7/07)	10.45	Unitholder Rights and Restrictions Agreement, dated as of May 7, 2007, by and among Energy Transfer Equity, L.P., Ray C. Davis, Natural Gas Partners VI, L.P. and Enterprise GP Holdings, L.P.
10.24	1-11727 (10-Q) (5/31/07)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
10.24.1	1-11727 (10-Q) (5/31/07)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.

Table of Contents

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
10.25	1-11727 (10-Q) (5/31/07)	10.6	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
10.26	1-32740 (8-K) (9/20/10)	10.1	Credit Agreement, dated September 20, 2010 among Energy Transfer Equity, L.P., as the borrower, Credit Suisse AG, as administrative agent and collateral agent, and the other lenders party thereto, and Credit Suisse Securities (USA) LLC, as sole lead arranger and sole book runner.
10.27	1-32740 (8-K) (9/20/10)	10.2	Pledge and Security Agreement, dated September 20, 2010, by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.L.C., ETE GP Acquirer LLC, ETE Services Company, LLC, Regency GP LLC, as the grantors, and Credit Suisse AG, Cayman Islands Branch, as collateral agent for the lenders under the Credit Agreement dated September 20, 2010.
10.28	1-32740 (8-K)(7/5/11)	10.5	Amended and Restated Support Agreement dated July 4, 2011 by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and certain stockholders of Southern Union Company
10.29	1-32740 (8-K)(7/20/11)	10.1	Second Amended and Restated Support Agreement, dated as of July 19, 2011, by and among, Energy Transfer Equity, L.P., Sigma Acquisition Corporation and certain stockholders of Southern Union Company.
10.30	1-32740 (10-Q)(8/8/11)	10.1.1	First Amendment to Credit Agreement, dated September 20, 2010 among Energy Transfer Equity, L.P., as the borrower, Credit Suisse AG, as administrative agent and collateral agent, and the other lenders party thereto, and Credit Suisse Securities (USA) LLC, as sole lead arranger and sole book runner.
10.31	1-32740 (8-K)(7/5/11)	10.1	Support Agreement dated June 15, 2011 by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and certain stockholders of Southern Union Company.
10.32	1-32740 (8-K)(10/21/11)	10.1	Senior Bridge Term Loan Credot Agreement, dated as of October 17, 2011 among Energy Transfer Equity, L.P., as the borrower, Credit Suisse AG, as administrative agent, and the other lenders party thereto, and Credit Suisse Securities (USA) LLC, as sole arranger and sole bookrunner.
10.33	1-32740 (8-K) (3/28/12)	10.1	Guarantee of Collection, made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. under the Indenture dated as of January 18, 2005, as supplemented by the Tenth Supplemental Indenture dated as of January 17, 2012.
10.34	1-32740 (8-K) (3/28/12)	10.2	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P. and Citrus ETP Finance LLC.
10.35	1-32740 (8-K) (3/28/12)	10.3	Senior Secured Term Loan Agreement dated March 23, 2012, by and among Energy Transfer Equity, L.P. and Credit Suisse AG,

			as Administrative Agent, and the other lenders from time to time party thereto.
10.36	1-32740 (8-K) (3/28/12)	10.4	Amendment No. 2 to Credit Agreement dated, as of March 23, 2012, by and among Energy Transfer Equity, L.P. and Credit Suisse AG, as Administrative Agent and the other lenders party thereto.
10.37	1-32740 (8-K) (5/1/12)	10.1	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
10.38	1-32740 (10-Q) (11/8/12)	10.1.1	Amendment No. 1 to Amended and Restated Credit Agreement dated as of September 13, 2012, between Energy Transfer Equity, L.P., several banks and other financial institutions signatories, and Credit Suisse AG, as Administrative Agent for the Lenders
10.39	1-32740 (8-K)(8/8/12)	10.1	Amendment No.1 to Senior Secured Term Loan Agreement by and among Energy Transfer Equity, L.P. (the “Borrower”), the Restricted Persons party thereto, the Lenders party thereto and Credit Suisse AG, in its capacity as administrative agent for the Lenders dated as of August 2, 2012.

Table of Contents

Exhibit Number	Previously Filed * With File Number (Form) (Period Ended or Date)	As Exhibit	
10.40	1-32740 (8-K)(12/17/12)	10.1	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Missouri Acquisition, Inc. and for certain limited purposes The Laclede Group, Inc.
10.41	1-32740 (8-K)(12/17/12)	10.2	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Massachusetts Acquisition, Inc. and for certain limited purposes The Laclede Group, Inc.
12.1			Computation of Ratio of Earnings to Fixed Charges.
21.1			List of Subsidiaries.
23.1			Consent of Grant Thornton LLP.
23.2			Consent of Ernst & Young LLP.
23.3			Consent of KPMG LLP.
23.4			Consent of PricewaterhouseCoopers LLP.
31.1			Certification of President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			Certification of President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1			Report of Independent Registered Public Accounting Firm — Ernst & Young LLP opinion on consolidated financial statements of Sunoco Logistics Partners LP.
99.2			Report of Independent Registered Public Accounting Firm — Ernst & Young LLP opinion on internal controls over financial reporting of Sunoco Logistics Partners LP.
99.3			Report of Independent Registered Public Accounting Firm — KPMG LLP opinion on consolidated financial statements of Regency Energy Partners LP.
99.4			Report of Independent Registered Public Accounting Firm — PricewaterhouseCoopers LLP opinion on financial statements of Midcontinent Express Pipeline LLC.
99.5	1-32740 (10-Q)(8/8/11)	99.1	Statement of Policies Relating to Potential Conflicts among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and Regency Energy Partners LP dated as of April 26, 2011.
101			Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2012 and December 31, 2011; (ii) our Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010; (iii) our Consolidated Statements of Comprehensive Income for years ended December 31, 2012, 2011 and 2010; (iv) our Consolidated Statement of Equity for the years ended December 31, 2012, 2011 and 2010; and (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010.

* Incorporated herein by reference.
** Denotes a management contract or compensatory plan or arrangement.

Table of Contents

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

Table of Contents

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, 2012 and 2011, 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, 2012. 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., is based solely on the report of the other auditors. We did not audit the consolidated financial statements of Regency Energy Partners LP, a consolidated subsidiary, for the period from May 26, 2010 to December 31, 2010, which statements reflect total revenues of 11 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 Regency Energy Partners LP for the period from May 26, 2010 to December 31, 2010, is based solely on the report of the other auditors.

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

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 1, 2013

Table of Contents

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

	December 31, 2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$372	$126
Accounts receivable, net of allowance for doubtful accounts of $2 and $9 as of December 31, 2012 and 2011, respectively	3,057	680
Accounts receivable from related companies	71	100
Inventories	1,522	328
Exchanges receivable	55	21
Price risk management assets	25	16
Current assets held for sale	184	—
Other current assets	311	184
Total current assets	5,597	1,455
PROPERTY, PLANT AND EQUIPMENT	30,388	16,530
ACCUMULATED DEPRECIATION	(2,104)	(1,971)
	28,284	14,559
NON-CURRENT ASSETS HELD FOR SALE	985	—
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,737	1,497
NON-CURRENT RISK MANAGEMENT ASSETS	43	26
GOODWILL	6,434	2,039
INTANGIBLE ASSETS, net	2,291	1,072
OTHER NON-CURRENT ASSETS, net	533	249
Total assets	$48,904	$20,897

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

Table of Contents

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

	December 31, 2012	2011
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,107	$512
Accounts payable to related companies	15	33
Exchanges payable	156	18
Price risk management liabilities	115	90
Accrued and other current liabilities	1,754	764
Current maturities of long-term debt	613	424
Current liabilities held for sale	85	—
Total current liabilities	5,845	1,841
NON-CURRENT LIABILITIES HELD FOR SALE	142	—
LONG-TERM DEBT, less current maturities	21,440	10,947
DEFERRED INCOME TAXES	3,566	217
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	162	81
PREFERRED UNITS (Note 7)	331	323
OTHER NON-CURRENT LIABILITIES	995	29
COMMITMENTS AND CONTINGENCIES (Note 11)		
PREFERRED UNITS OF SUBSIDIARY (Note 7)	73	71
EQUITY:		
General Partner	—	—
Limited Partners:		
Common Unitholders (279,955,608 and 222,972,708 units authorized, issued and outstanding as of December 31, 2012 and 2011, respectively)	2,125	52
Accumulated other comprehensive income (loss)	(12)	1
Total partners' capital	2,113	53
Noncontrolling interest	14,237	7,335
Total equity	16,350	7,388
Total liabilities and equity	$48,904	$20,897

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

Table of Contents

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

	Years Ended December 31,		
	2012	2011	2010
REVENUES:			
Natural gas sales	$2,705	$2,982	$2,730
NGL sales	2,253	1,716	826
Crude sales	2,872	—	—
Gathering, transportation and other fees	2,386	1,819	1,360
Refined product sales	5,299	—	—
Other	1,449	1,673	1,640
Total revenues	16,964	8,190	6,556
COSTS AND EXPENSES:			
Cost of products sold	13,088	5,169	4,102
Operating expenses	1,065	906	771
Depreciation and amortization	871	586	406
Selling, general and administrative	580	292	233
Total costs and expenses	15,604	6,953	5,512
OPERATING INCOME	1,360	1,237	1,044
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(1,018)	(740)	(625)
Bridge loan related fees	(62)	—	—
Equity in earnings of unconsolidated affiliates	212	117	65
Gain on deconsolidation of Propane Business	1,057	—	—
Losses on extinguishments of debt	(123)	—	(16)
Losses on non-hedged interest rate derivatives	(19)	(78)	(52)
Impairments of investments in affiliates	—	(5)	(53)
Other, net	30	17	(4)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,437	548	359
Income tax expense from continuing operations	54	17	14
INCOME FROM CONTINUING OPERATIONS	1,383	531	345
Loss from discontinued operations	(109)	(3)	(8)
NET INCOME	1,274	528	337
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	970	218	144
NET INCOME ATTRIBUTABLE TO PARTNERS	304	310	193
GENERAL PARTNER’S INTEREST IN NET INCOME	2	1	1
LIMITED PARTNERS’ INTEREST IN NET INCOME	$302	$309	$192
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$1.17	$1.39	$0.87
Diluted	$1.17	$1.38	$0.87
NET INCOME PER LIMITED PARTNER UNIT:			
Basic	$1.13	$1.39	$0.86
Diluted	$1.13	$1.38	$0.86

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

Table of Contents

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

	Years Ended December 31,		
	2012	2011	2010
Net income	$1,274	$528	$337
Other comprehensive income, net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17)	(19)	49
Change in value of derivative instruments accounted for as cash flow hedges	12	7	19
Change in value of available-for-sale securities	—	(1)	(4)
Change in other comprehensive income from equity investments	(9)	—	—
Actuarial loss relating to pension and other postretirement benefits	(10)	—	—
	(24)	(13)	64
Comprehensive income	1,250	515	401
Less: Comprehensive income attributable to noncontrolling interest	959	209	150
Comprehensive income attributable to partners	$291	$306	$251

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

Table of Contents

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

	General Partner	Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2009	$—	$53	$(53)	$3,220	$3,220
Regency Transactions (See Note 3)	1	209	—	1,895	2,105
Distributions to partners	(1)	(482)	—	—	(483)
Distributions to noncontrolling interest	—	—	—	(568)	(568)
Subsidiary units issued for cash	—	142	—	1,410	1,552
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	—	25	26
Other, net	—	(1)	—	(5)	(6)
Other comprehensive income, net of tax	—	—	58	6	64
Net income	1	192	—	144	337
Balance, December 31, 2010	1	114	5	6,127	6,247
Distributions to partners	(2)	(524)	—	—	(526)
Distributions to noncontrolling interest	—	—	—	(779)	(779)
Subsidiary units issued for cash	—	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 income, 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 units issued for cash	—	33	—	1,070	1,103
Subsidiary units issued in acquisitions	—	47	—	2,248	2,295
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	—	31	32
Capital contributions 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

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

Table of Contents

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

	Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$1,274	$528	$337
Reconciliation of net income to net cash provided by operating activities:			
Impairments of investments in affiliates	—	5	53
Payment for termination of Parent Company interest rate derivatives	—	—	(169)
Proceeds from termination of ETP interest rate derivatives	—	—	26
Depreciation and amortization	871	586	406
Deferred income taxes	51	1	4
Gain on curtailment of other postretirement benefit plans	(15)	—	—
Amortization of finance costs charged to interest	(13)	20	18
Bridge loan related fees	62	—	—
Non-cash compensation expense	47	42	31
Gain on deconsolidation of Propane Business	(1,057)	—	—
Losses on extinguishments of debt	123	—	16
Losses on disposal of assets	4	1	5
Equity in earnings of unconsolidated affiliates	(212)	(117)	(65)
Distributions from unconsolidated affiliates	208	126	149
LIFO valuation reserve	75	—	—
Other non-cash	211	28	17
Net change in operating assets and liabilities, net of effects of acquisitions, dispositions and deconsolidation (see Note 2)	(551)	158	260
Net cash provided by operating activities	1,078	1,378	1,088
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Southern Union Merger, net of cash received (See Note 3)	(2,972)	—	—
Cash received from (paid) all other acquisitions	(10)	(1,972)	(345)
Capital expenditures (excluding allowance for equity funds used during construction)	(3,271)	(1,810)	(1,510)
Contributions in aid of construction costs	35	25	14
Contributions to unconsolidated affiliates	(37)	(222)	(93)
Distributions from unconsolidated affiliates in excess of cumulative earnings	189	72	—
Proceeds from sale of disposal group	207	—	—
Proceeds from the sale of assets	44	33	104
Cash proceeds from contribution of propane operations	1,443	—	—
Other	176	—	—
Net cash used in investing activities	(4,196)	(3,874)	(1,830)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	12,870	8,262	4,389
Repayments of long-term debt	(8,848)	(6,264)	(4,078)
Subsidiary equity offerings, net of issue costs	1,103	1,903	1,552
Distributions to partners	(666)	(526)	(483)
Distributions to noncontrolling interests	(1,017)	(779)	(568)
Debt issuance costs	(112)	(53)	(49)

Capital contributions received from noncontrolling interest	42	—	—
Other, net	(8)	(7)	(3)
Net cash provided by financing activities	3,364	2,536	760
INCREASE IN CASH AND CASH EQUIVALENTS	246	40	18
CASH AND CASH EQUIVALENTS, beginning of period	126	86	68
CASH AND CASH EQUIVALENTS, end of period	$372	$126	$86

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

Table of Contents

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar 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, 2012, 2011 and 2010, 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.

We obtained control of Regency on May 26, 2010 as a result of the Regency Transactions. On March 26, 2012, we acquired all of the outstanding shares of Southern Union for approximately $3.01 billion in cash and approximately 57 million ETE Common Units. On October 5, 2012, ETP completed the Sunoco Merger and we and ETP also completed the Holdco Transaction at that time. See Note 3 for more information regarding the Regency Transactions, the Southern Union Merger, Sunoco Merger and Holdco Transaction.

At December 31, 2012, our equity interests in Regency and ETP consisted of:

	General Partner Interest (as a % of total partnership interest)	Incentive Distribution Rights (“IDRs”)	Limited Partner Units
ETP	0.9 %	100 %	50,226,967
Regency	1.6 %	100 %	26,266,791

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”);
- Holdco, in which we own a 60% interest and ETP owns the remaining 40%, which includes the operations of Southern Union and Sunoco; and
- 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 Regency Transactions in May 2010, the Southern Union Merger in March 2012 and the Holdco Transaction in October 2012, the periods presented herein do not include activities from Regency, 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 2012 presentation. In October 2012, we sold Canyon for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been adjusted to present Canyon's operations as discontinued operations. Canyon was previously included in our midstream segment. In December 2012, Southern Union entered into a purchase and sale agreement pursuant to which subsidiaries of Laclede Gas Company, Inc. have agreed to acquire the assets of Southern Union's Missouri Gas Energy and New England Gas Company divisions. For the period from March 26, 2012 to December 31, 2012 the results of operations of distribution operations have been reclassified to income from discontinued operations. The assets and liabilities of the disposal group have been reclassified and reported as assets and liabilities held for sale as of December 31, 2012.

Table of Contents

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, Southern Union, 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 have historically derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency. Effective with the acquisition of Southern Union in March 2012, the Parent Company also generated cash flows through its wholly-owned subsidiary, Southern Union until its contribution of Southern Union to Holdco on October 5, 2012. Subsequent to October 5, 2012, we also generate cash flows from our direct investment in Holdco. 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. 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 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. Our intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus 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 is owned 40% and 60% by ETP and ETE, respectively. Holdco directly owns Southern Union and Sunoco. Pursuant to a stockholders agreement between ETE and ETP, ETP controls Holdco. As such, ETP consolidates Holdco (including Sunoco and Southern Union) in its financial statements which their operations are described as follows:

Southern Union owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States.

Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores in 25 states, primarily on the east coast and in the midwest region of the United States.

Table of Contents

Regency is a publicly traded partnership engaged in the gathering and processing, contract 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 Haynesville, Eagle Ford, Barnett, Fayetteville, Bone Spring, Avalon and Marcellus shales, as well as the Permian Delaware basin and the mid-continent region. Its assets are located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, West Virginia and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma. Regency also holds a 30% interest in Lone Star.

Subsequent to the Holdco Transaction on October 5, 2012, our reportable segments changed and currently reflect the following reportable business segments: Intrastate Transportation and Storage, Interstate Transportation and Storage; Midstream; NGL Transportation and Services; Retail Marketing; Investment in Sunoco Logistics; Investment in Regency; and Corporate and Other.

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

Certain of our significant accounting policies have been impacted by current year transactions. See Note 3 for a discussion of these transactions.

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.

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

Our intrastate transportation and storage and interstate transportation and storage segments’ results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. Fuel retained for a fee is typically valued at market prices.

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

Table of Contents

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices, (iv) purchasing all or a specified percentage of natural gas and/or NGL delivered from producers and treating or processing our plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing objectives. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

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

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

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

Our retail marketing segment sells gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. In addition some of Sunoco's retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in

accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.
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.

Regulatory Accounting - Regulatory Assets and Liabilities

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

Southern Union records regulatory assets with respect to its distribution segment operations. We recorded regulatory assets with respect to Southern Union's distribution operations, which have been classified as discontinued operations as of December 31, 2012. At December 31, 2012, we had $123 million of regulatory assets included in the consolidated balance sheet as non-current assets held for sale. Although Panhandle’s natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

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

Table of Contents

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,		
	2012	2011	2010
Accounts receivable	$267	$6	$92
Accounts receivable from related companies	(9)	(24)	(26)
Inventories	(258)	51	15
Exchanges receivable	14	1	1
Other current assets	597	(51)	33
Other non-current assets, net	(129)	7	6
Accounts payable	(989)	21	(67)
Accounts payable to related companies	92	6	(10)
Exchanges payable	—	2	(4)
Accrued and other current liabilities	(159)	84	74
Other non-current liabilities	26	—	—
Price risk management assets and liabilities, net	(3)	55	146
Net change in operating assets and liabilities, net of effects of acquisitions, dispositions and deconsolidation	$(551)	$158	$260

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

	Years Ended December 31,		
	2012	2011	2010
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$420	$226	$108
Net gain from subsidiary common unit transactions	$80	$153	$352
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 from acquisitions	$6,658	$4	$1,243
Subsidiary issuance of Common Units in connection with certain acquisitions	$2,295	$3	$584
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$997	$728	$547
Cash paid for income taxes	$23	$27	$9

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

Table of Contents

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,	
	2012	2011
Natural gas and NGLs, excluding propane	$338	$146
Propane	—	87
Crude oil	418	—
Refined products	572	—
Appliances, parts and fittings and other	194	95
Total inventories	$1,522	$328

ETP utilizes commodity derivatives to manage price volatility associated with its natural gas inventory and designates certain of these derivatives as fair value hedges for accounting purposes. Changes in fair value of designated hedged inventory is 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,	
	2012	2011
Deposits paid to vendors	$41	$66
Prepaid and other	270	118
Total other current assets	$311	$184

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 AFUDC is accrued. Interest is capitalized based on the current borrowing rate when the related costs are incurred. AFUDC is

Table of Contents

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,	
	2012	2011
Land and improvements	$553	$137
Buildings and improvements (5 to 40 years)	587	279
Pipelines and equipment (5 to 83 years)	19,505	11,359
Natural gas and NGL storage facilities (5 to 46 years)	1,057	790
Bulk storage, equipment and facilities (5 to 83 years)	1,745	977
Tanks and other equipment (10 to 40 years)	1,194	644
Retail equipment (3 to 99 years)	258	—
Vehicles (3 to 25 years)	96	231
Right of way (20 to 83 years)	2,134	793
Furniture and fixtures (3 to 12 years)	50	48
Linepack	118	59
Pad gas	58	58
Other (2 to 19 years)	1,060	234
Construction work-in-process	1,973	921
	30,388	16,530
Less - Accumulated depreciation	(2,104)	(1,971)
Property, plant and equipment, net	$28,284	$14,559

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

	Years Ended December 31,		
	2012	2011	2010
Depreciation expense [(1)]	$801	$531	$370
Capitalized interest, excluding AFUDC	$99	$13	$4

(1) Depreciation expense amounts have been adjusted by $26 million and $25 million for the years ended December 31, 2011 and 2010, respectively, 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 in which we have a 20% to 50% ownership and exercise significant influence over, but do not control the investee’s operating and financial policies. See Note 4 for a discussion of these joint ventures.

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, as of November 30 for the Southern Union reporting units and as of December 31 for all others, including all of Regency’s reporting units. No goodwill impairments were recorded for the periods presented in these consolidated financial statements.

Table of Contents

Changes in the carrying amount of goodwill were as follows:

	Balance, December 31, 2010	Goodwill acquired	Balance, December 31, 2011	Goodwill acquired	Disposal of Goodwill [1]	Balance, December 31, 2012
ETP Intrastate Transportation and Storage	$10	$—	$10	$—	—	$10
ETP Interstate Transportation and Storage	99	—	99	1,785	—	1,884
ETP Midstream	50	—	50	338	—	388
ETP NGL Transportation and Services	—	432	432	—	—	432
ETP Retail Marketing	—	—	—	1,272	—	1,272
Investment in Sunoco Logistics	—	—	—	1,368	—	1,368
Investment in Regency	790	—	790	—	—	790
Corporate and Other	652	6	658	384	(752)	290
Total	$1,601	$438	$2,039	$5,147	$(752)	$6,434

[1] Includes goodwill deconsolidated or disposed of during the year ended December 31, 2012 and goodwill reclassified to non-current assets held for sale at December 31, 2012.

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. A net increase in goodwill of $4.40 billion was recorded during the year ended December 31, 2012, primarily due to $2.64 billion from the Sunoco Merger and $2.50 billion related to Southern Union, offset by $619 million in goodwill that was contributed as part of the deconsolidation of ETP's Propane Business, and $133 million classified as assets held for sale. This additional goodwill is not expected to be deductible for tax purposes.

See further discussion regarding our acquisitions at Note 3.

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, 2012		December 31, 2011	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$2,032	$(150)	$1,059	$(135)
Trade names (20 years)	66	(8)	66	(5)
Noncompete agreements (3 to 15 years)	—	—	15	(8)
Patents (9 years)	48	(1)	1	—
Other (10 to 15 years)	4	(1)	1	(1)
Total amortizable intangible assets	2,150	(160)	1,142	(149)
Non-amortizable intangible assets:				
Trademarks	301	—	79	—
Total intangible assets	$2,451	$(160)	$1,221	$(149)

During 2012, in connection with the Southern Union Merger and Holdco Transaction, we recorded customer contracts of $1.07 billion with useful lives ranging from 5 to 20 years, patents of $48 million with useful lives of 10 years and non-amortizable trademarks of $301 million.

Table of Contents

Aggregate amortization expense of intangibles assets was as follows:

	Years Ended December 31,		
	2012	2011	2010
Reported in depreciation and amortization	$70	$55	$36

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

Years Ending December 31:	
2013	$116
2014	115
2015	115
2016	115
2017	115

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,	
	2012	2011
Unamortized financing costs (3 to 30 years)	$152	$132
Regulatory assets	93	89
Deferred charges	140	—
Other	148	28
Total other non-current assets, net	$533	$249

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, 2012 and 2011 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

Table of Contents

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 as of December 31, 2012:

Southern Union	$46
Sunoco	53
Sunoco Logistics	41
	$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, 2012, 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,	
	2012	2011
Interest payable	$334	$204
Customer advances and deposits	61	101
Accrued capital expenditures	427	229
Accrued wages and benefits	250	80
Taxes payable other than income taxes	208	79
Income taxes payable	41	15
Deferred income taxes	130	—
Other	303	56
Total accrued and other current liabilities	$1,754	$764

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.

We have marketable securities, commodity derivatives, interest rate derivatives, the Preferred Units 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

F - 19

Table of Contents

to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. 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. The fair value of the Preferred Units was based predominantly on an income approach model and is also considered Level 3.

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, 2012 and 2011 was $24.15 billion and $12.21 billion, respectively. As of December 31, 2012 and 2011, the aggregate carrying amount of our consolidated debt obligations was $22.05 billion and $11.37 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

Table of Contents

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, 2012 and 2011 based on inputs used to derive their fair values:

	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	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	(8)	(1)	(7)	—
Total commodity derivatives	(168)	(118)	(50)	—
Total Liabilities	$(759)	$(118)	$(285)	$(356)

Table of Contents

	Fair Value Measurements at December 31, 2011 Using			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Marketable securities (included in other current assets)	$ 1	$ 1	$ —	$ —
Interest rate derivatives	36	—	36	—
Commodity derivatives:				
Condensate — Forward Swaps	1	—	1	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	63	63	—	—
Swing Swaps IFERC	15	2	13	—
Fixed Swaps/Futures	219	215	4	—
Options — Puts	6	—	6	—
Forward Physical Swaps	1	—	1	—
Total commodity derivatives	305	280	25	—
Total Assets	$ 342	$ 281	$ 61	$ —
Liabilities:				
Interest rate derivatives	$ (117)	$ —	$ (117)	$ —
Series A Convertible Preferred Units	(323)	—	—	(323)
Embedded derivatives in the Regency Preferred Units	(39)	—	—	(39)
Commodity derivatives:				
Condensate — Forward Swaps	(2)	—	(2)	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	(82)	(82)	—	—
Swing Swaps IFERC	(16)	(3)	(13)	—
Fixed Swaps/Futures	(148)	(148)	—	—
Forward Physical Swaps	(1)	—	(1)	—
NGLs — Forward Swaps	(9)	—	(9)	—
Propane — Forward Swaps	(4)	—	(4)	—
Total commodity derivatives	(262)	(233)	(29)	—
Total Liabilities	$ (741)	$ (233)	$ (146)	$ (362)

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

	Unobservable Input	December 31, 2012
Preferred Units	Assumed Yield	6.11 %
Embedded derivatives in the Regency Preferred Units	Credit Spread	6.49 %
	Volatility	21.38 %

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.

Table of Contents

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, 2012. There were no transfers between the fair value hierarchy levels during the years ended December 31, 2012 or 2011.

Balance, December 31, 2011	$(362	)
Net unrealized gains included in other income (expense)	6	
Balance, December 31, 2012	$(356	)

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 totaled $25 million, $40 million and $43 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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 segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income.

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 Internal Revenue Service 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, 2012, 2011 and 2010, 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, formed via the Holdco Transaction (see Note 3), which includes Sunoco and Southern Union, is included amongst these corporate subsidiaries. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Table of Contents

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. See Note 10 for income tax disclosures.

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 non-hedged interest rate derivatives" in the consolidated statements of operations. See Note 12 for additional information related to interest rate derivatives.

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

Table of Contents

liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through AOCI in stockholders' equity.

See Note 13 for additional related information.

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 (see Note 8).

3. ACQUISITIONS AND RELATED TRANSACTIONS:

2012 Transactions

Southern Union Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union is the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE until our contribution to Holdco discussed below. The assets acquired as a result of this merger significantly expand our existing geographic footprint of natural gas pipeline and natural gas transportation capacity and into natural gas utilities distribution, and are complementary to the assets owned and operated by our other entities.

Under the terms of the merger agreement, Southern Union stockholders received a total of 56,982,160 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 2.25 million ETP Common Units. See Note 4 for more information regarding ETP's equity method investment in Citrus.

In connection with the Citrus Acquisition, we relinquished our rights to an aggregate $220 million of incentive distributions from ETP that we would otherwise be entitled to receive over 16 consecutive quarters following the closing of the merger.

Pursuant to the merger agreement, we also granted ETP a right of first offer with respect to any disposition by us or SUGS, a subsidiary of Southern Union that owns and operates a natural gas gathering and processing system serving the Permian Basin in West Texas and New Mexico.

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.

Sunoco Logistics is a publicly traded limited partnership that owns and operates a logistics business consisting of a geographically diverse portfolio of complementary pipeline, terminalling and crude oil acquisition and marketing assets. The refined products pipelines business consists of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in refined products pipelines. The crude oil pipeline business consists of crude oil pipelines located principally in Oklahoma and Texas. The terminal facilities business consists of refined products and crude oil terminal capacity at the Nederland Terminal on the Gulf Coast of Texas and capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey. The crude oil acquisition and marketing business, principally conducted in Oklahoma and Texas, involves the acquisition and marketing of crude oil and consists of crude oil transport trucks and crude oil truck unloading facilities.

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

Table of Contents

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 30% 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 ten-year supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

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 90,706,000 Class F Units representing limited partner interests in ETP. The ETP Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per ETP Class F Unit per year, which is the current distribution level. Pursuant to a stockholders agreement between ETE and ETP, ETP controls Holdco. Consequently, 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 relinquished an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The relinquishment applied to the distribution paid with respect to the quarter ended September 30, 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. Management is continuing to validate certain assumptions made in connection with the purchase price allocation of Sunoco. 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.

Table of Contents

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

	Sunoco [1]	Southern Union[2]
Total 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, including 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.

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.

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 $1.5 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.5 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

We have not reflected the Propane operations 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.

Discontinued Operations

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 the midstream segment.

Table of Contents

In December 2012, Southern Union entered into a purchase and sale agreement with the Laclede Entities, pursuant to which Laclede Missouri has agreed to acquire the assets of Missouri Gas Energy division and Laclede Massachusetts has agreed to acquire the assets of the New England Gas Company division. Total consideration is expected to be $1.04 billion, subject to customary closing adjustments, less the assumption of approximately $19 million of debt. For the period from March 26, 2012 to December 31, 2012 the results of continuing operations of distribution operations have been reclassified to income from discontinued operations. The assets and liabilities of the disposal group have been reclassified and reported as assets and liabilities held for sale as of December 31, 2012.
Below is selected financial information related to Southern Union's distribution operations for the period from March 26, 2012 to December 31, 2012:

Revenue from discontinued operations	$324
Net loss of discontinued operations, excluding effect of taxes and overhead allocations	43

The goodwill allocated to the disposal group was $133 million at December 31, 2012.

SUGS Contribution

On February 27, 2013, Southern Union entered into a definitive contribution agreement to contribute to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration to be paid by Regency in connection with this transaction will consist of (i) the issuance of 31,372,419 Regency common units to Southern Union, (ii) the issuance of 6,274,483 Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units will 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. Upon the closing of the transaction, we will agree to forego all distributions with respect to our IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing. The transaction is expected to close in the second quarter of 2013.

2011 Transactions

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 Energy Asset Holdings LLC (“LDH”), from Louis Dreyfus Highbridge Energy LLC (“Louis Dreyfus”) for approximately $1.98 billion in cash (the “LDH Acquisition”), including working capital adjustments. 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 expands 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 our NGL transportation and services reporting segment, while Lone Star’s results are recorded as an equity method investment in our Investment in Regency reporting 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.

Table of Contents

2010 Transactions

Regency Transactions

On May 26, 2010, we acquired our equity interests in Regency in a series of transactions, which we refer to as the Regency Transactions. In the Regency Transactions, we:

- acquired the general partner interest and IDRs in Regency in exchange for 3,000,000 Preferred Units having an aggregate liquidation preference of $300 million;
- acquired from ETP an indirect 49.9% interest in Midcontinent Express Pipeline LLC ("MEP"), ETP's joint venture with Kinder Morgan Energy Partners, L.P. ("KMP") to operate the Midcontinent Express Pipeline, and an option to acquire an additional 0.1% interest in MEP in exchange for the redemption by ETP of approximately 12 million ETP Common Units we previously owned; and
- acquired 26 million Regency Common Units in exchange for our contribution of all of our interests in MEP, including the option to acquire an additional 0.1% interest, to Regency.

We accounted for the Regency Transactions using the purchase method of accounting. The purchase price was $305 million, which was the fair value of the 3,000,000 Preferred Units exchanged in connection with the Regency Transactions.

Other Acquisitions

In March 2010, ETP purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, ETP recorded customer contracts of $68 million and goodwill of $27 million.

In September 2010, Regency completed its acquisition of Zephyr, a Texas based field services company for approximately $193 million in cash. In connection with this transaction, Regency recorded intangible assets of $119 million and no goodwill.

Dispositions

In July 2010, Regency sold its East Texas gathering and processing assets to an affiliate of Tristream Energy LLC for approximately $70 million in cash. The net loss from these assets is classified as discontinued operations in the consolidated statements of operations from the date of the Regency Transactions to the date of the sale.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended 2012 and 2011 are presented as if the Sunoco Merger and Holdco Transaction had been completed on January 1, 2011 and the LDH Acquisition had been completed on January 1, 2010.

	Year Ended December 31,		
	2012	2011	2010
Revenues	$40,398	$37,560	$7,407
Net income	868	865	358
Net income attributable to partners	866	863	228
Basic net income (loss) per Limited Partner unit	$3.09	$3.08	$1.02
Diluted net income (loss) per Limited Partner unit	$3.09	$3.08	$1.02

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.

F - 29

Table of Contents

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

AmeriGas Partners, L.P.

On January 12, 2012, ETP contributed its Propane Business to AmeriGas in exchange for approximately $1.46 billion in cash and approximately 30 million AmeriGas Common Units valued at $1.12 billion at the time of the contribution. In addition, AmeriGas assumed approximately $71 million of existing debt of the Propane Business. ETP recognized a gain on deconsolidation of $1.06 billion as a result of this transaction.

ETP's investment in AmeriGas initially reflected $630 million in excess of the proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $289 million is being amortized over a weighted average period of 14 years and $341 million is being treated as equity method goodwill and non-amortizable intangible assets.

We have not reflected the Propane operations as discontinued operations as a result of ETP's investment in AmeriGas. 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.

ETP's investment in AmeriGas was $1.02 billion as of December 31, 2012 and was reflected in our corporate and other segment.

Citrus Corp.

ETP acquired a 50% interest in Citrus, which owns 100% of FGT on March 26, 2012. A subsidiary of Kinder Morgan, Inc. owns the remaining 50% interest in Citrus. In exchange for the interest in Citrus, Southern Union received $1.9 billion in cash and $105 million of ETP Common Units. ETP initially 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. ETP's investment in Citrus was $1.98 billion at December 31, 2012 and is reflected in our interstate transportation and storage segment.

Fayetteville Express Pipeline LLC

ETP owns a 50% interest in FEP, which owns 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.

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.

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.

Table of Contents

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,	
	2012	2011
Current assets	$945	$893
Property, plant and equipment, net	10,979	10,393
Other assets	2,677	962
Total assets	$14,601	$12,248
Current liabilities	$1,662	$1,548
Non-current liabilities	7,024	5,778
Equity	5,915	4,922
Total liabilities and equity	$14,601	$12,248

	Years Ended December 31,		
	2012	2011	2010
Revenue	$4,492	$3,784	$3,287
Operating income	863	928	716
Net income	491	536	506

Table of Contents

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 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 have a liquidation preference of $300 million and are subject to mandatory conversion 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,		
	2012	2011	2010
Income from continuing operations	$1,383	$531	$345
Less: Income from continuing operations attributable to noncontrolling interest	1,070	221	149
Income from continuing operations, net of noncontrolling interest	313	310	196
Less: General Partner's interest in income from continuing operations	1	1	1
Income from continuing operations available to Limited Partners	$312	$309	$195
Basic Income from Continuing Operations per Limited Partner Unit:			
Weighted average limited partner units	266,722,030	222,968,261	222,941,156
Basic income from continuing operations per Limited Partner unit	$1.17	$1.39	$0.87
Basic loss from discontinued operations per Limited Partner unit	$(0.04)	$—	$(0.01)
Diluted Income from Continuing Operations per Limited Partner Unit:			
Income from continuing operations available to Limited Partners	$312	$309	$195
Dilutive effect of equity-based compensation of subsidiaries	(1)	(1)	—
Diluted income from continuing operations available to Limited Partners	311	308	195
Weighted average limited partner units	266,722,030	222,968,261	222,941,156
Diluted income from continuing operations per Limited Partner unit	$1.17	$1.38	$0.87
Diluted loss from discontinued operations per Limited Partner unit	$(0.04)	$—	$(0.01)

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2012	2011
Parent Company Indebtedness:		
ETE Senior Notes, due October 15, 2020	$1,800	$1,800
ETE Senior Secured Term Loan, due March 26, 2017	2,000	—
ETE Senior Secured Revolving Credit Facility	60	72
Other	19	1
Unamortized premiums, discounts and fair value adjustments, net	(34)	(1)
	3,845	1,872

Subsidiary Indebtedness:
ETP Debt

Table of Contents

5.65% Senior Notes due August 1, 2012	—	400
6.0% Senior Notes due July 1, 2013	350	350
8.5% Senior Notes due April 15, 2014	292	350
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	600
9.0% Senior Notes due April 15, 2019	450	650
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	—
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	—
ETP $2.5 billion Revolving Credit Facility due October 27, 2016	1,395	314
Other	—	81
Unamortized premiums, discounts and fair value adjustments, net	(14)	(2)
	9,073	6,943
Panhandle Debt		
6.05% Senior Notes due August 15, 2013	250	—
6.2% Senior Notes due November 1, 2017	300	—
7.0% Senior Notes due June 15, 2018	400	—
8.125% Senior Notes due June 1, 2019	150	—
7.0% Senior Notes due July 15, 2029	66	—
Term Loan due February 23, 2015	455	—
Unamortized premiums, discounts and fair value adjustments, net	136	—
	1,757	—
Regency Debt		
9.375% Senior Notes due June 1, 2016	162	250
6.875% Senior Notes due December 1, 2018	600	600
6.5% Senior Notes due July 15, 2021	500	500
5.5% Senior Notes due April 15, 2023	700	—
Regency Revolving Credit Facility	192	332
Unamortized premiums, discounts and fair value adjustments, net	3	5
	2,157	1,687
Southern Union Debt		
7.6% Senior Notes due February 1, 2024	360	—
8.25% Senior Notes due November 14, 2029	300	—
7.2% Junior Subordinated Notes due November 1, 2066	600	—
Southern Union Revolving Credit Facility	210	—
Other	7	—
Unamortized premiums, discounts and fair value adjustments, net	49	—
	1,526	—
Sunoco Debt		
4.875% Senior Notes due October 15, 2014	250	—
9.625% Senior Notes due April 15, 2015	250	—
5.75% Senior Notes due January 15, 2017	400	—
9.00% Debentures due November 1, 2024	65	—
Other	25	—

Unamortized premiums, discounts and fair value adjustments, net	104	—
	1,094	—
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014	175	—
6.125% Senior Notes due May 15, 2016	175	—
5.50% Senior Notes due February 15, 2020	250	—
4.65% Senior Notes due February 15, 2022	300	—
6.85% Senior Notes due February 15, 2040	250	—
6.10% Senior Notes due February 15, 2042	300	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2013	26	—
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	20	—
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	93	—
Unamortized premiums, discounts and fair value adjustments, net	143	—
	1,732	—

Table of Contents

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
	22,053	11,371
Current maturities	(613)	(424)
	$21,440	$10,947

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $386 million in unamortized premiums and fair value adjustments, net:

2013	$613
2014	1,003
2015	1,540
2016	2,073
2017	3,184
Thereafter	13,254
Total	$21,667

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.

ETP as Co-Obligor of Sunoco Debt

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

Senior Notes

ETE Senior Notes

We used the net proceeds from our Senior Secured Term Loan, along with proceeds received from ETP in the Citrus Acquisition, to fund the cash portion of the Southern Union Merger and pay related fees and expenses, including existing borrowings under our revolving credit facility and for general partnership purposes.

Borrowings bear interest at either the Eurodollar rate plus an applicable margin or the alternative base rate plus an applicable margin. The alternative base rate used to calculate interest on base rate loans will be calculated using the greater of a prime rate, a federal funds effective rate plus 0.50%, and an adjusted one-month LIBOR rate plus 1.00%. The applicable margins are 3.0% for Eurodollar loans and from 2.0% for base rate loans. The effective interest rate on the amount outstanding as of December 31, 2012 was 3.75%.

The ETE Senior Notes are unsecured obligations of ETE and the obligation to repay the ETE Senior Notes is not guaranteed by any of ETE’s subsidiaries, including ETP, Regency, and their respective subsidiaries. The indebtedness of ETP and Regency and their respective subsidiaries effectively ranks senior to the ETE Senior Notes.

Southern Union Junior Subordinated Notes

Southern Union has interest rate swap agreements that effectively fix the interest rate applicable to the floating rate on $525 million of the $600 million Junior Subordinated Notes due 2066. The interest rate on the remaining notes 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 $75 million at an effective interest rate of 3.32% at December 31, 2012.

Table of Contents

Panhandle Term Loans

In February 2012, Southern Union refinanced LNG Holdings' $455 million term loan due March 2012 with an unsecured three-year term loan facility due February 23, 2015, with LNG Holdings as borrower and PEPL and Trunkline LNG as guarantors and a floating interest rate tied to LIBOR plus a margin based on the rating of PEPL's senior unsecured debt. The effective interest rate of PEPL's term loan was 1.84% at December 31, 2012.

Bridge Term Loan Facility

Upon obtaining permanent financing for the Southern Union Merger in March 2012, we terminated the 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.

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.

January 2013 Senior Notes Offering

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 approximately $1.24 billion from this offering to repay borrowings outstanding under its revolving credit facility and for general partnership purposes.

In addition, in January 2013, Sunoco Logistics issued $350 million of 3.45% Senior Notes and $350 million of 4.95% Senior Notes (the “2023 and 2043 Senior Notes”), due January 2023 and January 2043, respectively. The terms and conditions of the 2023 and 2043 Senior Notes are comparable to those under Sunoco Logistics' existing Senior Notes. The net proceeds of $691 million from the 2023 and 2043 Senior Notes were used to pay outstanding borrowings under the $350 million and $200 million Sunoco Logistics Credit Facilities and for general partnership purposes.

Transwestern Senior Notes

The Transwestern Pipeline Company, LLC (“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.

Revolving Credit Facilities

ETE Senior Secured Credit Facility

The Parent Company has a $200 million five-year senior secured revolving credit facility (the “Parent Company Credit Agreement”) available through September 20, 2015. Under the Parent Company Credit Agreement, the obligations of ETE are secured by all tangible and intangible assets of ETE and certain of its subsidiaries, including (i) its ownership of ETP Common Units; (ii) ETE’s equity interest in ETP LLC and ETP GP, through which ETE holds the IDRs in ETP; (iii) the Common Units of Regency; and (iv) ETE’s equity interest in Regency GP LLC and Regency GP LP, through which ETE holds the IDRs in Regency.

Borrowings bear interest, at ETE’s option, at either the Eurodollar rate plus an applicable margin or the alternative base rate. The alternative base rate used to calculate interest on base rate loans will be calculated using the greater of a prime rate, a federal funds effective rate plus 0.50%, and an adjusted one-month LIBOR rate plus 1.00%. The applicable margins are based upon ETE’s leverage ratio and range from 2.75% to 3.75% for Eurodollar loans and from 1.75% to 2.75% for base rate loans. The commitment fee payable on the unused portion of the Parent Company Credit Agreement is based on ETE’s leverage ratio and ranges from 0.50% to 0.75%.

Table of Contents

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

As of December 31, 2012, we had a balance of $60 million outstanding under the Parent Company Credit Agreement and the amount available for future borrowings was $140 million. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 4.06%.

ETP Credit Facility

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.

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

ETP used approximately $2.0 billion of Sunoco's cash on hand to partially fund the cash portion of the Sunoco Merger consideration. The remainder of the cash portion of the merger consideration, approximately $620 million, was funded with borrowings under the ETP Credit Facility.

As of December 31, 2012, ETP had a balance of $1.40 billion outstanding under the ETP Credit Facility and, taking into account letters of credit of approximately $72 million, $1.03 billion available for future borrowings. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 1.71%.

Regency Credit Facility

The Regency Credit Facility has aggregate revolving commitments of $1.15 billion, with $200 million of availability for letters of credit that matures June 15, 2014. As of December 31, 2012, Regency had a balance of $192 million outstanding under the Regency Credit Facility in revolving credit loans and approximately $12 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2012, which is reduced by any letters of credit, was approximately $946 million. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 2.93%.

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 1.50% to 2.25% for base rate loans and 2.50% to 3.25% for Eurodollar loans. Regency pays (i) a commitment fee ranging between 0.375% and 0.50% 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 2.50% and 3.25% 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 0.125% 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.

Southern Union Credit Facility

The Southern Union Credit Facility provides for a $700 million revolving credit facility which matures on May 20, 2016. Borrowings under the Southern Union Credit Facility are available for working capital, other general company purposes and letter of credit requirements. The interest rate and commitment fee under the Southern Union Credit Facility are calculated using a pricing grid, which is based on the credit ratings for Southern Union's senior unsecured notes. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 1.84%.

On August 10, 2012, Southern Union entered into a First Amendment of the Southern Union Credit Facility. The amendment provides for, among other things, (i) a revision to the change of control definition to permit equity ownership of Southern

Table of Contents

Union by ETP or any direct subsidiaries of ETP in addition to ETE or any direct or indirect subsidiary of ETE; and (ii) a waiver of any potential default that may result from the Holdco Transaction.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains two credit facilities to fund the Partnership's working capital requirements, finance acquisitions and capital projects and for general partnership purposes. The credit facilities consist of a $350 million unsecured credit facility which expires in August 2016 (the "$350 million Credit Facility") and a $200 million unsecured credit facility which expires in August 2013 (the "$200 million Credit Facility"). Outstanding borrowings under $350 million Credit Facility and $200 million Credit Facility were $93 million and $26 million, respectively, at December 31, 2012.

In May 2012, Sunoco Logistics' West Texas Gulf entered into a $35 million revolving credit facility (the "$35 million 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 $20 million at December 31, 2012.

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The Parent Company Credit Agreement contains customary representations, warranties and covenants, including financial covenants regarding a maximum leverage ratio, a maximum consolidated leverage ratio, a minimum fixed charge coverage ratio and a minimum loan to value ratio. In addition, the Parent Company Credit Agreement contains customary events of default, including, but not limited to, (i) default for failure to pay the principal on any loan or any reimbursement obligation with respect to any letter of credit when due and payable, (ii) failure to duly observe, perform or comply with certain specified covenants, (iii) a representation or warranty made in connection with any loan document proves to have been false or incorrect in any material respect on any date on or as of which made, and (iv) the occurrence of a change of control.

The Parent Company Senior Secured Revolving Credit Facility contains financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to Consolidated EBITDA (as defined in the agreements) of the Parent Company of not more than 4.5 to 1, with a permitted increase to 5 to 1 during a specified acquisition period extending for two fiscal quarters following the close of a specified acquisition;
- Maximum Consolidated Leverage Ratio – Consolidated Funded Debt of the Parent Company, ETP and Regency to Consolidated EBITDA of ETP and Regency of not more than 5.5 to 1;
- Fixed Charge Coverage Ratio of not less than 3 to 1; and
- Value to Loan Ratio of not less than 2 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

Table of Contents

- 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 5.25 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 2.75 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 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. Under the current credit agreements, the financial covenants are as follows:

- Under the Southern Union Credit Facility, the ratio of consolidated funded debt to consolidated earnings before interest, taxes, depreciation and amortization, as defined therein, cannot exceed 5.25 times through December 31, 2012 and 5.00 times thereafter;
- Under the Southern Union Credit Facility, in the event Southern Union's credit rating falls below investment grade, the ratio of consolidated earnings before interest, taxes, depreciation and amortization to consolidated interest expense, as defined therein, cannot be less than 2.00 times;
- Under LNG Holding's $455 million term loan, the ratio of consolidated funded debt to consolidated earnings before interest, taxes, depreciation and amortization, as defined therein, for Panhandle cannot exceed 5.00 times.

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' $350 and $200 million Credit Facilities contain various covenants limiting the Partnership's 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 the Operating Partnership's 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' $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, 2012 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.

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, 2012.

7. REDEEMABLE PREFERRED UNITS:

ETE Preferred Units

In connection with the Regency Transactions as discussed in Note 3, ETE issued 3,000,000 Preferred Units to an affiliate of GE Energy Financial Services, Inc. ("GE EFS") having an aggregate liquidation preference of $300 million and are reflected as long-term liabilities in our consolidated balance sheets as of December 31, 2012 and 2011. The Preferred Units were issued in a private placement at a stated price of $100 per unit and are entitled to a preferential quarterly cash distribution of $2.00 per Preferred Unit. The Preferred Units will automatically convert on the fourth anniversary of the date of issuance into an amount of ETE Common Units equal in value to the issue price plus any accrued but unpaid distributions plus a specified premium equal to the lesser of 10% of the issue price plus any accrued but unpaid distributions or a premium derived from 25% of the accretion in the trading price of ETE Common Units subsequent to the date of issuance of the Preferred Units. ETE may choose, at its sole option, to pay 50% of the conversion consideration based on the issue price plus any accrued but unpaid distributions in cash. ETE may elect to redeem all, but not less than all, of the Preferred Units beginning on the third anniversary of the date of issuance for ETE Common Units or cash equal to the issue price plus a premium paid out in common units, equal to the greater of 10% of the issue price plus any accrued but unpaid distributions or a premium derived from 25% of the accretion in the trading price of ETE Common Units subsequent to the date of issuance. GE EFS also has certain rights to force ETE to redeem or convert the outstanding Preferred Units for specified consideration upon the occurrence of certain extraordinary events involving ETE or ETP. Holders of the Preferred Units have no voting rights, except that approval of a majority of the Preferred Units is needed to approve any amendment to ETE's Partnership Agreement that would result in (i) any increase in the size of the class of Preferred Units, (ii) any alteration or change to the rights, preferences, privileges, duties, or obligations of the Preferred Units or (iii) any other matter that would adversely affect the rights or preferences of the Preferred Units, including in relation to other classes of ETE partnership interests. 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. During 2011, we recorded non-cash charges of approximately $5 million to increase the carrying value of the Preferred Units to the estimated fair value of $323 million as of December 31, 2011.

Preferred Units of Subsidiary

Regency had 4,371,586 Regency Preferred Units outstanding at December 31, 2012, which were convertible into 4,658,700 Regency Common Units. If outstanding on September 2, 2029 the Regency Preferred Units are mandatorily redeemable for $80 million plus all accrued but unpaid distributions thereon. Holders of the Regency Preferred Units receive fixed Regency quarterly cash distributions of $0.445 per unit. Holders can elect to convert Regency Preferred Units to Regency Common Units at any time in accordance with Regency's partnership agreement.

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

	Regency Preferred Units	Amount
Balance, December 31, 2011	4,371,586	$71
Accretion to redemption value	—	2
Balance, December 31, 2012	4,371,586	$73

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, 2012, there were issued and outstanding 279,955,608 Common Units representing an aggregate 99.75% 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

Table of Contents

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, 2012, 2011 and 2010 was as follows:

	Years Ended December 31,		
	2012	2011	2010
Number of Common Units, beginning of period	222,972,708	222,941,172	222,898,248
Issuance of restricted Common Units under long-term incentive plan	740	31,536	42,924
Issuance of common units in connection with Southern Union Merger (See Note 3)	56,982,160	—	—
Number of Common Units, end of period	279,955,608	222,972,708	222,941,172

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.

As a result of ETP's and Regency's issuances and redemptions of Common Units, we have recognized increases in partners' capital of $80 million, $153 million and $352 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Sale of Common Units by ETP

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

Date	Number of ETP Common Units [(1)]	Price per ETP Unit	Net Proceeds	Use of Proceeds
January 2010	9,775,000	$44.72	$424	(2)(3)
August 2010	10,925,000	46.22	489	(2)(3)
April 2011	14,202,500	50.52	695	(3)
November 2011	15,237,500	44.67	660	(2)(3)
July 2012	15,525,000	44.57	671	(2)(3)

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.

(2) Proceeds were used to repay amounts outstanding under the ETP Credit Facility.

(3) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

ETP issued 90,706,000 ETP Class F Units in connection with the Holdco Transaction that are reported as treasury units, which are entitled to receive distributions in accordance with their terms, see Note 3.

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, ETP entered into an equity distribution agreement with Merrill Lynch, Pierce, Fenner & Smith Incorporated ("BofA Merrill Lynch"). According to the provisions of this agreement, ETP may offer and sell from time to time through BofA Merrill Lynch, as its sales agent, ETP Common Units having an aggregate offering price of up to $200 million. Under

F - 41

Table of Contents

the terms of this agreement, ETP may also sell ETP Common Units to BofA Merrill Lynch as principal for its own account at a price agreed upon at the time of sale. Any sale of ETP Common Units to BofA Merrill Lynch as principal would be pursuant to the terms of a separate agreement between us and BofA Merrill Lynch.

ETP's Equity Incentive Plan Activity

As discussed in Note 9, ETP issues ETP Common Units to employees and directors upon vesting of awards grander 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 which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

ETP’s Distribution Reinvestment Program

In April 2011, ETP filed a registration statement with the SEC covering its 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 Common Units. The registration statement covers the issuance of up to 5,750,000 Common Units under the DRIP.

During 2012, distributions of approximately $43 million were reinvested under the DRIP resulting in the issuance of 1,038,825 ETP Common Units.

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	Use of Proceeds
August 2010	17,537,500	$23.80	$400	[2]
May 2011	8,500,001	[4]	204	[3]
October 2011	11,500,000	20.92	232	[2]
March 2012	12,650,000	24.47	297	[2][3]

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.

(2) Proceeds were used to repay amounts outstanding under the Regency Credit Facility.

(3) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

(4) Regency Units were issued in a private placement.

On June 19, 2012, Regency entered into an Equity Distribution Agreement with Citi under which Regency may offer and sell Regency Common Units, 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. During the year ended December 31, 2012, Regency issued 691,129 Regency Common Units pursuant to its Equity Distribution Agreement with Citi and received net proceeds of $15 million.

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. In order to maintain its general partner interest in ETP, ETP GP was previously required to make contributions to ETP each time ETP issued limited partner interests for cash or in connection with acquisitions. These contributions were generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP. In July 2009, ETP amended and restated its partnership

Table of Contents

agreement, and as a result, ETP GP is no longer required to make corresponding contributions to maintain its general partner interest in ETP.

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, and distributions related to its 60% interest in Holdco. We currently have no independent operations outside of our direct and indirect interests in ETP, Regency and Holdco.

Our distributions declared during the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per ETE Common Unit
September 30, 2012	November 6, 2012	November 16, 2012	$0.6250
June 30, 2012	August 6, 2012	August 17, 2012	0.6250
March 31, 2012	May 4, 2012	May 18, 2012	0.6250
December 31, 2011	February 7, 2012	February 17, 2012	0.6250
September 30, 2011	November 4, 2011	November 18, 2011	$0.6250
June 30, 2011	August 5, 2011	August 19, 2011	0.6250
March 31, 2011	May 6, 2011	May 19, 2011	0.5600
December 31, 2010	February 7, 2011	February 18, 2011	0.5400
September 30, 2010	November 8, 2010	November 19, 2010	$0.5400
June 30, 2010	August 9, 2010	August 19, 2010	0.5400
March 31, 2010	May 7, 2010	May 19, 2010	0.5400
December 31, 2009	February 8, 2010	February 19, 2010	0.5400

On January 28, 2013, the Parent Company declared a cash distribution for the three months ended December 31, 2012 of $0.635 per Common Unit, or $2.54 annualized. We paid this distribution on February 19, 2013 to Unitholders of record at the close of business on February 7, 2013.

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.

Table of Contents

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

Quarter Ended	Record Date	Payment Date	Distribution per ETP Common Unit
September 30, 2012	November 6, 2012	November 14, 2012	$0.89375
June 30, 2012	August 6, 2012	August 14, 2012	0.89375
March 31, 2012	May 4, 2012	May 15, 2012	0.89375
December 31, 2011	February 7, 2012	February 14, 2012	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	$0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
December 31, 2010	February 7, 2011	February 14, 2011	0.89375
September 30, 2010	November 8, 2010	November 15, 2010	$0.89375
June 30, 2010	August 9, 2010	August 16, 2010	0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375
December 31, 2009	February 8, 2010	February 15, 2010	0.89375

On January 28, 2013, ETP declared a cash distribution for the three months ended December 31, 2012 of $0.89375 per ETP Common Unit, or $3.575 annualized. ETP paid this distribution on February 14, 2013 to ETP Unitholders of record at the close of business on February 7, 2013.

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
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
September 30, 2010	November 5, 2010	November 12, 2010	$0.445
June 30, 2010	August 6, 2010	August 13, 2010	0.445

On January 28, 2013, Regency declared a cash distribution for the three months ended December 31, 2012 of $0.46 per Regency Common Unit, or $1.84 annualized. Regency paid this distribution on February 14, 2013 to Regency Unitholders of record at the close of business on February 7, 2013.

Table of Contents

Accumulated Other Comprehensive Income (Loss)

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

	December 31,	
	2012	2011
Net gains (losses) on commodity related hedges	$(3)	$2
Actuarial loss related to pensions and other postretirement benefits	(10)	—
Equity investments, net	(9)	—
Subtotal	(22)	2
Amounts attributable to noncontrolling interest	10	(1)
Total AOCI included in partners’ capital, net of tax	$(12)	$1

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

	December 31,	
	2012	2011
Net gains on commodity related hedges	$2	$—
Actuarial loss relating to pension and other postretirement benefits	5	—
Total	$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 3,000,000 units. As of December 31, 2012, 2,852,936 units remain available to be awarded under the plan.

During 2012, no awards were granted to ETE employees and 740 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 2012, a total of 28,325 ETE units vested, with a total fair value of $1 million as of the vesting date. As of December 31, 2012, a total of 54,972 restricted units granted to ETE employees and directors remain outstanding, for which we expect to recognize a total of $1 million in compensation over a weighted average period of 1.9 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 period at 20% per year, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each 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.”

Table of Contents

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

Award Activity

The following table shows the activity of the 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, 2011	2,563,709	$46.37
Awards granted	289,930	43.93
Awards vested	(647,498)	44.58
Awards forfeited	(346,982)	44.58
Unvested awards as of December 31, 2012	1,859,159	46.95

During the years ended December 31, 2012, 2011 and 2010, the weighted average grant-date fair value per unit award granted was $43.93, $48.35 and $49.82, respectively. The total fair value of awards vested was $29 million, $27 million and $17 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2012, a total of 1,859,159 unit awards remain unvested, for which ETP expects to recognize a total of $51 million in compensation expense over a weighted average period of 1.8 years.

Sunoco Logistics Unit-Based Compensation Plan

Sunoco Logistics' general partner has a long-term incentive plan for employees and directors, which permits the grant of restricted units and unit options of Sunoco Logistics covering an additional 0.9 million Sunoco common units. As of December 31, 2012, a total of 427,610 Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $10 million of expense over a weighted-average period of 2.5 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 will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE.

ETP is recognizing 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, 2012, 2011 and 2010, ETP recognized non-cash compensation expense, net of forfeitures, of $1 million, $2 million and $4 million, respectively, as a result of these awards. As of December 31, 2012, rights related to 90,000 ETE common units remain outstanding, for which ETP expects to recognize a total of less than $1 million in compensation expense over a weighted average period of 0.6 years.

Regency Unit-Based Compensation Plans

Regency has the following awards outstanding as of December 31, 2012:

- 156,550 Regency Common Unit options, all of which are exercisable, with a weighted average exercise price of $21.96 per unit option;
- no Regency restricted (non-vested) Common Units; and
- 1,226,542 Regency Phantom Units, with a weighted average grant date fair value of $23.22 per Phantom Unit.

In conjunction with the Regency Transactions, certain of Regency's then-outstanding Phantom Units converted to 252,630 Regency Common Units as a result of change-in-control provisions associated with the awards. Each of Regency's outstanding Phantom Units as of December 31, 2012 is the economic equivalent of one Regency Common Unit and is

Table of Contents

accompanied by a distribution equivalent right, entitling the holder to an amount equal to any cash distributions paid on Regency Common Units. The outstanding Regency Phantom Units will vest one-third on each March 15th through 2013.

Regency expects to recognize $26 million of compensation expense related to the Regency Phantom Units over a weighted average period of five 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,		
	2012	2011	2010
Current expense (benefit):			
Federal	$(3)	$(1)	$1
State	6	17	9
Total	3	16	10
Deferred expense:			
Federal	41	—	3
State	10	1	1
Total	51	1	4
Total income tax expense from continuing operations	$54	$17	$14

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 year ended December 31, 2012 is a as follows:

	Holdco [1]	Other Corporate Subsidiaries [2]	Partnership [3]	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35%	$(1)	$(3)	$—	$(4)
Increase (reduction) in income taxes resulting from:				
Nondeductible executive compensation	28	—	—	28
State income taxes (net of federal income tax effects)	9	—	2	11
Other	17	2	—	19
Income Tax from continuing operations	$53	$(1)	$2	$54

(1) Holdco, which was formed via the Sunoco Merger and the Holdco transactions (see Note 3), includes Sunoco and Southern Union and their subsidiaries.

(2) Includes Oasis Pipeline Company, Pueblo Holdings Inc. (Pueblo), Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. The latter three entities were acquired in the Sunoco transaction.

(3) Includes Energy Transfer Equity, L.P. and its subsidiaries that are classified as pass-through entities for federal income tax purposes.

Table of Contents

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, 2012	2011
Deferred tax assets:		
Net operating losses and alternative minimum tax credit	$270	$4
Pension and other postretirement benefits	127	—
Long term debt	117	—
Other	290	4
Total deferred income tax assets	804	8
Valuation allowance	(94)	(3)
Net deferred income tax assets	710	5
Deferred income tax liabilities:		
Properties, plants and equipment	(2,026)	(147)
Inventory	(516)	—
Investments in unconsolidated affiliates	(1,543)	(72)
Trademarks	(192)	—
Other	(129)	—
Total deferred income tax liabilities	(4,406)	(219)
Net deferred income tax liability	(3,696)	(214)
Less: current portion of deferred income tax asset (liabilities)	(130)	3
Accumulated deferred income taxes	$(3,566)	$(217)

The completion of the Southern Union, Sunoco and Holdco transactions (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, 2012
Net deferred income tax liability, beginning of year	$(214)
Southern Union acquisition	(1,428)
Sunoco acquisition	(1,989)
Tax provision (including discontinued operations)	(62)
Other	(3)
Net deferred income tax liability	$(3,696)

Holdco and other corporate subsidiaries have gross federal net operating loss carryforwards of $368 million, of which $1 million, $3 million, $18 million, $40 million and $306 million will expire in 2028, 2029, 2030, 2031 and 2032, respectively. Holdco has $37 million of federal alternative minimum tax credit which do not expire. Holdco and other corporate subsidiaries have state net operating loss carryforward benefits of $104 million, net of federal tax which expire between 2013 and 2032. The valuation allowance is applicable to the federal net operating loss benefits and state net operating loss benefits of $4 million and $90 million, respectively. The valuation allowance of $90 million for state net operating loss benefits is applicable to Sunoco pre-acquisition periods. The valuation for federal net operating loss benefits increased $1 million in 2012.

Table of Contents

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

	Years Ended December 31,		
	2012	2011	2010
Balance at beginning of year	$2	$2	$1
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	—	—	1
Lapse of statute	(3)	(1)	—
Balance at end of year	$27	$2	$2

As of December 31, 2012, we have $24 million ($16 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 $5 million ($3 million, net of federal tax) within the next 12 months due to settlement of certain positions.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2012, we recognized interest and penalties of less than $1 million. At December 31, 2012, we have interest and penalties accrued of $5 million, net of tax.

In general, ETE and its subsidiaries are no longer subject to examination by the Internal Revenue Service 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. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2012, 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 and Pueblo are also under examination by the IRS for the 2007 and 2008 and the 2007 to 2009 tax years, respectively. The IRS has proposed adjustments in both of these examinations which are under review at the Appeals level. We believe Regency and Pueblo will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to these tax positions. Neither of the proposed adjustments with respect to Regency or Pueblo would 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:

Regulatory Matters

Southern Union and its Subsidiaries

The FERC is currently conducting an audit of PEPL, a subsidiary of Southern Union, 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. The audit is related to the period from January 1, 2010 through December 31, 2011 and is pending the issuance of a draft audit report.

Contingent Residual Support Agreement - AmeriGas

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

Table of Contents

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

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 $60 million, $29 million and $24 million for the years ended December 31, 2012, 2011 and 2010, respectively, which include contingent rentals totaling $6 million in 2012. During the three months ended December 31, 2012, approximately $4 million of rental expense was recovered through related sublease rental income.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2013	$92	
2014	82	
2015	79	
2016	64	
2017	52	
Thereafter	462	
Future minimum lease commitments	831	
Less: Sublease rental income	(64	)
Net future minimum lease commitments	$767	

Amounts reflected above do not include future minimum lease commitments for the Southern Union's distribution operations, which were reclassified and reported as assets and liabilities held for sale at December 31, 2012 as described in Note 3.

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.

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, 2012 and 2011, accruals of approximately $15 million and $18 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, 2012 or 2011 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Will Price. Will Price, an individual, filed actions in the U.S. District Court for the District of Kansas for damages against a number of companies, including Panhandle, alleging mis-measurement of natural gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On September 19, 2009, the Court denied plaintiffs' request for class certification. Plaintiffs have filed a motion for reconsideration, which the Court denied on March 31, 2010. Panhandle believes that its measurement practices conformed to the terms of its FERC natural gas tariffs, which were filed with and approved by the FERC. As a result, Southern Union believes that it has meritorious defenses to the Will Price lawsuit (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Panhandle complied with the terms of its tariffs). In the event that Plaintiffs refuse Panhandle's pending request for voluntary dismissal, Panhandle will continue to vigorously defend the case. Southern Union believes it has no liability associated with this proceeding.

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 $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 stayed discovery until resolution of a separate matter concerning the applicability of attorney-client privilege to legal billing invoices. 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. Additionally, New England Gas Company's assets and liabilities have been included in discontinued operations at December 31, 2012.

Air Quality Control. SUGS is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ.

Compliance Orders from the New Mexico Environmental Department. SUGS has been in discussions with the New Mexico Environmental Department concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. The New Mexico Environmental Department has issued amended compliance orders and proposed penalties for alleged violations at Jal #4 in the amount of $1 million and at Jal #3 in the amount of $7 million. Hearings on the compliance orders were delayed until May 2013 to allow the parties to pursue substantive settlement discussions. SUGS has meritorious defenses to the New Mexico Environmental Department claims and can offer significant mitigating factors to the claimed violations. SUGS has recorded an accrued liability and will continue to assess its potential exposure to the allegations as the matter progresses.

FGT Pipeline Relocation Costs. The FDOT/FTE has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGT's mainline pipelines located in FDOT/FTE rights-of-way. Several FDOT/FTE projects are the subject of litigation in Broward County, Florida. On January 27, 2011, a jury awarded FGT $83 million and rejected all damage claims by the FDOT/FTE. On May 2, 2011, the judge issued an order entitling FGT to an easement of 15 feet on either side of its pipelines and 75 feet of temporary work space. The judge further ruled that FGT is entitled to approximately $8 million in interest. In addition to ruling on other aspects of the easement, he ruled that pavement could not be placed directly over FGT's pipeline without the consent of FGT although FGT would be required to relocate the pipeline if it did not provide such consent. While FGT would seek reimbursement of any costs associated with relocation of its pipeline in connection with an FDOT project, FGT may not be successful in obtaining such reimbursement and, as such, could be required to bear the cost of such relocation. In any such instance, FGT would seek recovery of the reimbursement costs in rates. The judge also denied all other pending post-trial motions. The FDOT/FTE filed a notice of appeal on July 12, 2011.

Table of Contents

On June 6, 2012, Florida's Fourth District Court of Appeal (“4th DCA”) issued an opinion affirming the jury award of damages and also affirming or remanding for further consideration by the trial court certain other determinations with respect to FGT's easement rights and FDOT/FTE's obligations regarding future FDOT/FTE projects. In particular, the 4th DCA affirmed that FDOT/FTE could not pave directly over our pipeline without FBT's consent and remanded and directed the trial court to make reference in the final judgment to FDOT/FTE's obligation to seek reasonable alternatives to relocation. The 4th DCA did overturn the portion of the trial court judgment defining the width of FGT's easements as 15 feet on either side of its pipelines and defining the temporary work space available to Florida Gas under its easements as 75 feet in width, stating that the width of such easements and temporary work space should be determined on a case by case basis dependent on the needs of each particular relocation and whether a road improvement is a material interference with the easement. Reimbursement for any future relocation expenses will also be determined on a case by case basis. As a result of the decision by the 4th DCA affirming the monetary award of the judgment and the trial court's November 7, 2012 issuance of a peremptory writ of mandamus, FDOT paid to FGT on November 16, 2012 the sum of $100 million, representing the amount of judgment plus interest through that date. The amounts received reduced FGTs' property, plant and equipment costs. FGT previously filed a petition requesting the Supreme Court of Florida to exercise its discretionary jurisdiction and to reverse the portion of the 4th DCA decision overturning the trial court judgment specifically defining the width of FGTs' easements and temporary work space. By order dated December 28, 2012, the Supreme Court of Florida denied that petition.

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.

The Texas case remains pending, and discovery is ongoing.

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 deadline for the remaining defendants to file an answer or otherwise respond is March 1, 2013. Trial in this action is not currently set.

Table of Contents

CrossCountry, a “Principal” under the Citrus capital stock agreement, filed a complaint in the Delaware Court of Chancery against El Paso Citrus Holdings, Inc. (“EPCH”) and its parent El Paso Corp. (“El Paso”) seeking a declaratory judgment that the Citrus Acquisition does not, as El Paso contended, trigger any provisions of the capital stock agreement that would require Southern Union to provide El Paso a right of first refusal (ROFR) concerning Citrus. The complaint was filed by CrossCountry following an exchange of letters between El Paso and Southern Union regarding the terms of the capital stock agreement. Following the filing of the declaratory judgment action, El Paso filed a third-party complaint against Southern Union, ETE, and ETP alleging, among other things, breach the capital stock agreement. El Paso was not seeking to enjoin the closing of the Citrus Acquisition, but rather sought a rescission of the Citrus Acquisition after it was completed or, alternatively, damages. All parties have agreed the Citrus Acquisition did not trigger a ROFR and the courts granted El Paso's dismissal of its claims for rescission or damages with prejudice on April 20, 2012.

Litigation Related to Sunoco Merger

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 is pending approval by the state court.

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, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2012, Sunoco was a defendant in two lawsuits involving one state and Puerto Rico. These cases are venued in a multidistrict proceeding in a New York federal court. Both 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.

Discovery is proceeding in these cases. There has been insufficient information developed about the plaintiffs' legal theories or the facts in the natural resource damage claims that would be relevant to an analysis of the ultimate liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that the MBTE cases could have a significant impact on results of operations for any future period, but does not believe that the cases will have a material adverse effect on its consolidated financial position.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, there can be no assurance that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, will not result in substantial costs and liabilities. We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Our subsidiaries have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage and to limit the financial liability which could result from such events. However, the risk of environmental or other damage is inherent in transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses. 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 subsidiaries' liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future.

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 CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require some of our subsidiaries 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 a direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule is required by October 2013.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require some of our subsidiaries to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if equipment is replaced or existing facilities are expanded 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 our subsidiaries might make in the future, but 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.

On April 17, 2012 the EPA issued the Oil and Natural Gas Sector New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. The standards revise the new source performance standards for volatile organic compounds from leaking components at onshore natural gas processing plants and new source performance standards for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by the existing standards. In addition to the operations covered by the existing standards, the newly established standards regulate volatile organic compound emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels. ETP is reviewing the new standards to determine the impact on its operations.

Our subsidiaries' pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause our subsidiaries to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Table of Contents

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 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, 2012, Sunoco had been named as a PRP at 35 identified or potentially identifiable as “Superfund” sites under federal and/or comparable state law. The Company 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, 2012	December 31, 2011
Current	$46	$4
Non-current	166	10
Total environmental liabilities	$212	$14

During the year ended December 31, 2012 the Partnership had $12 million of expenditures related to environmental cleanup programs.

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 hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot

market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.

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

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby the Company generally 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 for the residue gas and NGLs. We use derivative swap contracts to hedge forecasted sales of NGL 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.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading activities related to power in our “All Other” segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our midstream segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices.

Prior to the deconsolidation of the Propane Business, we also used propane futures contracts to fix the purchase price related to certain fixed price sales contracts. Prior to the sale of our cylinder exchange business, we used propane futures contracts to secure the purchase price of our propane inventory for a percentage of the anticipated sales.

Table of Contents

The following table details ETP's outstanding commodity-related derivatives:

	December 31, 2012		December 31, 2011	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX [(1)]	(30,980,000)	2013-2014	(151,260,000)	2012-2013
Power (Megawatt):				
Forwards	19,650	2013	—	—
Futures	(1,509,300)	2013	—	—
Options — Calls	1,656,400	2013	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	150,000	2013	(61,420,000)	2012-2013
Swing Swaps IFERC	(83,292,500)	2013	92,370,000	2012-2013
Fixed Swaps/Futures	27,077,500	2013	797,500	2012
Forward Physical Contracts	11,689,855	2013-2014	(10,672,028)	2012
Options — Puts	—	2013	—	—
NGLs (Bbls):				
Forwards/Swaps	(30,000)	2013	—	—
Refined Products (Bbls)	(666,000)	2013	—	—
Propane (Gallons):				
Forwards/Swaps	—	—	38,766,000	2012-2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(18,655,000)	2013	(28,752,500)	2012
Fixed Swaps/Futures	(44,272,500)	2013	(45,822,500)	2012
Hedged Item — Inventory	44,272,500	2013	45,822,500	2012
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	(8,212,500)	2013	—	—
Options — Puts	—	—	3,600,000	2012
Options — Calls	—	—	(3,600,000)	2012
NGLs (Bbls):				
Forwards/Swaps	(930,000)	2013	—	—
Refined Products (Bbls)	(98,000)	2013	—	—

[(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 losses of $6 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.

Table of Contents

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, 2012		December 31, 2011	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives (Non-Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	8,395,000	2013-2014	—	—
Propane (Gallons):				
Forwards/Swaps	3,318,000	2013	—	—
Natural Gas Liquids (Barrels):				
Forwards/Swaps	243,000	2013-2014	—	—
Options — Puts	—	—	110,000	2012
WTI Crude Oil (Barrels):				
Forwards/Swaps	356,000	2014	—	—
Cash Flow Hedging Derivatives (Non-Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	—	—	2,198,000	2012
Propane (Gallons):				
Forwards/Swaps	—	—	11,802,000	2012-2013
Natural Gas Liquids (Barrels):				
Forwards/Swaps	—	—	533,000	2012-2013
WTI Crude Oil (Barrels):				
Forwards/Swaps	—	—	350,000	2012-2014

As of December 31, 2011 all of the Regency’s commodity swap contracts were accounted for as cash flow hedges, and the Regency’s put options were accounted for on mark-to-market basis. On January 1, 2012, Regency, for accounting purposes, de-designated its swap contracts and will account for these contracts using the mark-to-market method of accounting. Regency has less than $1 million in net hedging gains in AOCI, the majority of which will be amortized to earnings over the next 12 months.

Table of Contents

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, 2012, none of which are designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type(1)	December 31, 2012	December 31, 2011
ETE	March 2017	Pay a fixed rate of 1.25% and receive a floating rate	$500	$—
ETP	May 2012 (2)	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	—	350
ETP	August 2012 (2)	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	—	500
ETP	July 2013 (2)	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	400	300
ETP	July 2014 (2)	Forward starting to pay a fixed rate of 4.26% and receive a floating rate	400	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	500
Regency	April 2012	Pay a fixed rate of 1.325% and receive a floating rate	—	250
Southern Union	November 2016	Pay a fixed rate of 2.913% and receive a floating rate	75	N/A
Southern Union	November 2021	Pay a fixed rate of 3.746% and receive a floating rate	450	N/A

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

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

As of December 31, 2012, Southern Union had no outstanding treasury rate locks; however, certain of its treasury rate locks that settled in prior periods are associated with interest payments on outstanding long-term debt. These treasury rate locks are accounted for as cash flow hedges, with the effective portion of their settled value recorded in AOCI and reclassified into interest expense in the same periods during which the related interest payments on long-term debt impact earnings.

In connection with ETE's offering of senior notes in September 2010, ETE terminated interest rate swaps with an aggregate notional amount of $1.5 billion and recognized in interest expense $66 million of realized losses on terminated interest rate swaps that had been accounted for as cash flow hedges. In addition to the $66 million of realized losses on hedged interest rate swaps, ETE also paid $102 million to terminate non-hedged interest rate swaps. The $102 million of realized losses on non-hedged interest rate swaps had previously been recognized in net income and therefore the termination of the non-hedged swaps did not impact earnings. The total cash paid to terminate interest rate swaps was $169 million, including realized losses on hedged and non-hedged swaps.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposures associated with a single or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrial, small to major oil and gas producers, midstream and power generation companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Currently, management does not anticipate a material adverse effect on financial our position or results of operations as a result of counterparty nonperformance.

Table of Contents

ETP utilizes master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds 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. ETP had net deposits with counterparties of $41 million and $66 million as of December 31, 2012 and 2011, respectively.

Regency is exposed to credit risk from its derivative counterparties. Although Regency does not require collateral from these counterparties, Regency deals primarily with financial institutions when entering into financial derivatives, and enters into Master International Swap Dealers Association (“ISDA”) Agreements that allow for netting of swap contract receivables and payables in the event of default by either party.

Certain of Southern Union’s derivative instruments contain provisions that require Southern Union’s debt to be maintained at an investment grade credit rating from each of the major credit rating agencies. If Southern Union’s debt were to fall below investment grade, Southern Union would be in violation of these provisions, and the counterparties to the derivative instruments could potentially require Southern Union to post collateral for certain of the derivative instruments. The aggregate fair value of Southern Union's derivative instruments with credit-risk-related contingent features that are in a net liability position at December 31, 2012 was $4 million, all of which were included in the disposal group held for sale liabilities and December 31, 2012.

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, 2012 and 2011:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	2012	2011	2012	2011
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$8	$77	$(10)	$(1)
Commodity derivatives	—	5	—	(10)
	8	82	(10)	(11)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	$110	$227	$(116)	$(251)
Commodity derivatives	40	1	(44)	(5)
Interest rate derivatives	55	36	(235)	(118)
Embedded derivatives in Regency Preferred Units	—	—	(25)	(39)
	205	264	(420)	(413)
Total derivatives	$213	$346	$(430)	$(424)

The commodity derivatives (margin deposits) are recorded in other current assets on our consolidated balance sheets. The remainder of the derivatives are recorded in price risk management assets or price risk management liabilities. As of December 31, 2012 commodity derivative assets of $1 million and commodity derivatives liabilities of $8 million were recorded as non-current assets held for sale and current liabilities held for sale in our consolidated balance sheet. In addition to the above derivatives, $7 million of option premiums included in price risk management liabilities as of December 31, 2012 will amortize in 2013.

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.

Table of Contents

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion) Years Ended December 31,		
	2012	2011	2010
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$8	$6	$50
Interest rate derivatives		—	(30)
Total	$8	$6	$20

	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,		
		2012	2011	2010
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$14	$19	$37
Interest rate derivatives	Interest expense, net	—	—	(87)
Total		$14	$19	$(50)

	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,		
		2012	2011	2010
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$54	$34	$16
Total		$54	$34	$16

	Location of Gain/ (Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives Years Ended December 31,		
		2012	2011	2010
Derivatives in cash flow hedging relationships:				
Commodity derivatives – Trading	Cost of products sold	$(7)	$(30)	$—
Commodity derivatives – Non-trading	Cost of products sold	26	9	4
Commodity derivatives – Non-trading	Deferred gas purchases	26	—	—
Interest rate derivatives	Losses on non-hedged interest rate derivatives	(19)	(78)	(52)
Embedded derivatives	Other income (expense)	14	18	(8)
Total		$40	$(81)	$(56)

13. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings 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 have made matching contributions of $11 million, $14 million and $10 million to the 401(k) savings plan for the years ended December 31, 2012, 2011 and 2010, respectively.

Regency previously sponsored its own 401(k) plan. Effective January 1, 2011, Regency's 401(k) plan merged with and into that of ETP. As a result of the Regency Transactions, Regency's matching contributions that had not yet fully vested became fully vested effective immediately. Regency made matching contributions of $2 million to its own 401(k) savings plan for period from May 26, 2010 to December 31, 2010.

Southern Union sponsors a defined contribution savings plan (Savings Plan) that is available to all employees. Southern Union contributions to the Savings Plan during the period from Acquisition (March 26, 2012) to December 31, 2012 were $6 million.

In addition, the Southern Union makes employer contributions to separate accounts, referred to as Retirement Power Accounts, within the defined contribution plan. The contribution amounts are determined as a percentage of compensation and range from 3.5% to 12%. Southern Union contributions are generally 100% vested after five years of continuous service. Southern Union contributions to Retirement Power Accounts during the period from Acquisition (March 26, 2012) to December 31, 2012 were $2 million.

Pension and Other Postretirement Benefit Plans

Southern Union

Southern Union has funded non-contributory defined benefit pension plans that cover substantially all employees of Southern Union's distribution operations. Normal retirement age is 65, but certain plan provisions allow for earlier retirement. Pension benefits are 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.

The 2012 postretirement benefits expense for Southern Union reflects the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. The Company previously had postretirement health care and life insurance plans that covered substantially all Distribution and Transportation and Storage segment employees, as well as all Corporate employees. The health care plans generally provide for cost sharing between Southern Union and its retirees in the form of retiree contributions, deductibles, coinsurance, and a fixed cost cap on the amount Southern Union pays annually to provide future retiree health care coverage under certain of these plans.

Table of Contents

Sunoco

Sunoco has both funded and unfunded noncontributory defined benefit pension plans (see "defined benefit 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, 2012			
	Pension Benefits		Other Postretirement Benefits	
Change in benefit obligation:				
Benefit obligation at acquisition date	$1,257		$359	
Service cost	3		1	
Interest cost	15		3	
Amendments	—		17	
Benefits paid, net	(71	)	(8	)
Curtailments	—		(80	)
Actuarial (gain)/loss and other	(9	)	4	
Benefit obligation at end of period	$1,195		$296	
Change in plan assets:				
Fair value of plan assets at acquisition date	$941		$306	
Return on plan assets and other	22		5	
Employer contributions	14		9	
Benefits paid, net	(71	)	(8	)
Fair value of plan assets at end of period	$906		$312	
Amount underfunded (overfunded) at end of period	$289		$(16	)
Amounts recognized in the consolidated balance sheets consist of:				
Noncurrent assets	$—		$59	
Current liabilities	(15	)	(2	)
Noncurrent liabilities	(274	)	(41	)
	$(289	)	$16	
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:				
Net actuarial gain	$(1	)	$(1	)
Prior service cost	—		16	
	$(1	)	$15	

F - 63

Table of Contents

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	Pension Benefits	Other Postretirement Benefits
Projected benefit obligation	$1,195	N/A
Accumulated benefit obligation	1,179	$225
Fair value of plan assets	906	185

Components of Net Periodic Benefit Cost

	December 31, 2012	
	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:		
Service cost	$3	$1
Interest cost	15	3
Expected return on plan assets	(21)	(5)
Special termination benefits charge	2	—
Curtailment recognition [1]	—	(15)
	(1)	(16)
Regulatory adjustment [2]	9	2
Net periodic benefit cost	$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) In its distribution operations, Southern Union recovers certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers. 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, 2012	
	Pension Benefits	Other Postretirement Benefits
Discount rate	3.41%	2.39%
Rate of compensation increase	3.17%	N/A

Table of Contents

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2012	
	Pension Benefits	Other Postretirement Benefits
Discount rate	2.37 %	2.43 %
Expected return on assets:		
Tax exempt accounts	7.63 %	7.00 %
Taxable accounts	N/A	4.50 %
Rate of compensation increase	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 other postretirement benefit plans are shown in the table below:

	December 31, 2012
Health care cost trend rate assumed for next year	7.78 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.32 %
Year that the rate reaches the ultimate trend rate	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.

Table of Contents

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	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, 2012	Fair Value Measurements at 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 $18 million to pension plans and approximately $8 million to other postretirement plans in 2013. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Table of Contents

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	Benefits	Other Postretirement Benefits (Gross, Before Medicare Part D)	Other Postretirement Benefits (Medicare Part D Subsidy Receipts)
2013	$ 254	$ 38	$ 1
2014	105	34	1
2015	98	33	1
2016	87	32	1
2017	82	30	1
2018 - 2021	328	107	4

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.

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.

Transactions between ETE's subsidiaries and Enterprise were previously considered to be related party transactions due to Enterprise's ownership of a portion of ETE's limited partner interests. During the years ended December 31, 2011 and 2010, subsidiaries of ETE recorded sales to Enterprise and $1.04 billion and $697 million, respectively, and purchases from Enterprise of $507 million and $444 million, respectively, all of which were related party transactions based on Enterprise's interests in ETE at the time of the transactions.

In addition, subsidiaries of ETE recorded sales with affiliates of $189 million during the year ended December 31, 2012.

Table of Contents

15. REPORTABLE SEGMENTS:
As a result of the Holdco Transactions in October 2012, our reportable segments were re-evaluated and currently reflect eight reportable segments, which conduct their business exclusively in the United States of America, as follows:
•Intrastate Transportation and Storage;
•Interstate Transportation and Storage;
•Midstream;
•NGL Transportation and Services;
•Retail Marketing;
•Investment in Sunoco Logistics;
•Investment in Regency; and
•Corporate and Other.
Revenues from the intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from the interstate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from the midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from the retail marketing segment are primarily reflected in retail marketing. Revenues from the investment in Sunoco Logistics segment are primarily reflected in crude sales. Revenues from Investment in Regency are primarily reflected in natural gas sales, NGL sales, gathering, transportation and other fees.

The amounts reflected as “Corporate and Other” include the Parent Company activity, the goodwill and property and plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P. and certain operating segments that do not meet quantitative thresholds for separate reporting.
We previously reported net income as a measure of segment performance. Due to the change in our reportable segments described above, the financial information available to our chief operating decision maker to assess the performance is now based on Segment Adjusted EBITDA. Therefore, we have accordingly revised our segment operating performance measure that we report. 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. 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.
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.

	Years Ended December 31,		
	2012	2011	2010
Revenues:			
Intrastate Transportation and Storage:			
Revenues from external customers	$2,010	$2,397	$2,075
Intersegment revenues	181	277	1,216
	2,191	2,674	3,291
Interstate Transportation and Storage:			
Revenues from external customers	1,109	447	292
Midstream:			
Revenues from external customers	2,604	1,989	1,914
Intersegment revenues	480	552	1,214
	3,084	2,541	3,128
NGL Transportation and Services:			
Revenues from external customers	619	363	—
Intersegment revenues	31	34	—
	650	397	—
Retail Marketing:			
Revenues from external customers	5,926	—	—
Investment in Sunoco Logistics:			
Revenues from external customers	3,114	—	—
Intersegment revenues	80	—	—
	3,194	—	—
Investment in Regency:			
Revenues from external customers	1,323	1,426	715
Intersegment revenues	16	8	1
	1,339	1,434	716
Corporate and Other:			
Revenues from external customers	290	1,622	1,707
Intersegment revenues	118	34	—
	408	1,656	1,707
Adjustments and Eliminations:	(937)	(959)	(2,578)
Total revenues	$16,964	$8,190	$6,556
Costs of products sold:			
Intrastate Transportation and Storage	$1,393	$1,774	$2,381
Midstream	2,432	2,072	2,750
NGL Transportation and Services	361	218	—
Retail Marketing	2,843	—	—
Investment in Sunoco Logistics	5,757	—	—
Investment in Regency	871	1,013	504
Corporate and Other	320	1,016	1,010
Adjustments and Eliminations	(889)	(924)	(2,543)
Total costs of products sold	$13,088	$5,169	$4,102
Depreciation and amortization:			
Intrastate Transportation and Storage	122	120	117
Interstate Transportation and Storage	209	81	53
Midstream	168	85	60
NGL Transportation and Services	53	32	—
Retail Marketing	28	—	—

Investment in Sunoco Logistics	63	—	—
Investment in Regency	201	169	76
Corporate and Other	27	99	100
Total depreciation and amortization	$871	$586	$406

Table of Contents

	As of December 31, 2012	2011	2010
Equity in earnings of unconsolidated affiliates:			
Intrastate Transportation and Storage	$4	$2	$9
Interstate Transportation and Storage	120	24	3
Midstream	(9)	—	—
NGL Transportation and Services	2	—	—
Retail Marketing	1	—	—
Investment in Sunoco Logistics	5	—	—
Investment in Regency	114	120	54
Corporate and Other	19	—	—
Adjustments and Eliminations	(44)	(29)	(1)
Total equity in earnings of unconsolidated affiliates	$212	$117	$65

	Years Ended December 31, 2012	2011	2010
Segment Adjusted EBITDA:			
Intrastate Transportation and Storage	$601	$667	$716
Interstate Transportation and Storage	1,013	373	220
Midstream	438	389	329
NGL Transportation and Services	209	127	—
Retail Marketing	109	—	—
Investment in Sunoco Logistics	219	—	—
Investment in Regency	480	422	218
Corporate and Other	36	153	255
Total	3,105	2,131	1,738
Depreciation and amortization	(871)	(586)	(406)
Interest expense, net of interest capitalized	(1,018)	(740)	(625)
Bridge loan related fees	(62)	—	—
Gain on deconsolidation of Propane Business	1,057	—	—
Losses on non-hedged interest rate derivatives	(19)	(78)	(52)
Non-cash unit-based compensation expense	(47)	(42)	(31)
Unrealized gains (losses) on commodity risk management activities	10	7	(110)
Losses on extinguishments of debt	(123)	—	(16)
LIFO valuation reserve	(75)	—	—
Proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on extinguishment of debt and taxes	(435)	(114)	(71)
Adjusted EBITDA related to discontinued operations	(99)	(23)	(19)
Other, net	14	(7)	(49)
Income from continuing operations before income tax expense	$1,437	$548	$359

Table of Contents

	As of December 31,	
	2012	2011
Total assets:		
Intrastate Transportation and Storage	$4,691	$4,785
Interstate Transportation and Storage	11,794	3,661
Midstream	5,098	2,666
NGL Transportation and Services	3,765	2,360
Retail Marketing	3,926	—
Investment in Sunoco Logistics	10,291	—
Investment in Regency	6,157	5,568
Corporate and Other	4,372	2,517
Adjustments and Eliminations	(1,190)	(660)
Total	$48,904	$20,897

	Years Ended December 31,		
	2012	2011	2010
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate Transportation and Storage	$38	$52	$117
Interstate Transportation and Storage	142	208	872
Midstream	1,355	837	405
NGL Transportation and Services [1]	1,304	1,745	—
Retail Marketing	47	—	—
Investment in Sunoco Logistics	141	—	—
Investment in Regency [2]	436	411	2,068
Corporate and Other	63	80	76
Total	$3,526	$3,333	$3,538

(1) The year ended December 31, 2011 includes $1.42 billion acquired in the LDH Acquisition.

(2) The year ended December 31, 2010 includes $1.55 billion acquired in the Regency Transactions.

	As of December 31,	
	2012	2011
Advances to and investments in affiliates:		
Intrastate Transportation and Storage	$2	$1
Interstate Transportation and Storage	2,142	173
Midstream	1	—
NGL Transportation and Services	29	27
Retail Marketing	21	—
Investment in Sunoco Logistics	118	—
Investment in Regency	2,214	1,925
Corporate and Other	1,158	—
Adjustments and Eliminations	(948)	(629)
Total	$4,737	$1,497

Table of Contents

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. For 2011, ETP's propane operations were seasonal due to weather conditions in their service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Sales to commercial and industrial customers are less weather sensitive. ETP's Energy Transfer Company ("ETC OLP") business is also seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

	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	961	75	(34)	272	1,274
Limited Partners' interest in net income	166	53	35	48	302
Basic net income per limited partner unit	$0.73	$0.19	$0.13	$0.17	$1.13
Diluted net income per limited partner unit	$0.73	$0.19	$0.13	$0.17	$1.13
2011:					
Revenues	$1,977	$1,963	$2,084	$2,166	$8,190
Gross margin	778	703	736	804	3,021
Operating income	363	263	272	339	1,237
Net income	199	107	61	161	528
Limited Partners' interest in net income	88	66	69	86	309
Basic net income per limited partner unit	$0.40	$0.30	$0.31	$0.38	$1.39
Diluted net income per limited partner unit	$0.40	$0.30	$0.31	$0.38	$1.38

Table of Contents

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, 2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$9	$18
Accounts receivable from related companies	11	1
Note receivable from affiliate	3	—
Other current assets	—	1
Total current assets	23	20
ADVANCES TO AND INVESTMENTS IN AFFILIATES	6,094	2,226
INTANGIBLE ASSETS, net	19	—
GOODWILL	9	—
OTHER NON-CURRENT ASSETS, net	222	50
Total assets	$6,367	$2,296
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$1	$—
Accounts payable to related companies	15	12
Interest payable	48	35
Price risk management liabilities	5	—
Accrued and other current liabilities	1	1
Current maturities of long-term debt	4	—
Total current liabilities	74	48
LONG-TERM DEBT, less current maturities	3,840	1,872
PREFERRED UNITS	331	323
OTHER NON-CURRENT LIABILITIES	9	—
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL:		
General Partner	—	—
Limited Partners – Common Unitholders (279,955,608 and 222,972,708 units authorized, issued and outstanding at December 31, 2012 and 2011, respectively)	2,125	52
Accumulated other comprehensive income (loss)	(12)	1
Total partners' capital	2,113	53
Total liabilities and partners' capital	$6,367	$2,296

Table of Contents

STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2012	2011	2010
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$(53)	$(30)	$(22)
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(235)	(164)	(168)
Bridge loan related fees	(62)	—	—
Equity in earnings of affiliates	666	509	456
Losses on non-hedged interest rate derivatives	(15)	—	(53)
Other, net	(4)	(5)	(20)
INCOME BEFORE INCOME TAXES	297	310	193
Income tax benefit	(7)	—	—
NET INCOME	304	310	193
GENERAL PARTNER’S INTEREST IN NET INCOME	2	1	1
LIMITED PARTNERS’ INTEREST IN NET INCOME	$302	$309	$192

Table of Contents

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2012	2011	2010
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$555	$469	$317
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions	(1,113)	—	—
Contributions to affiliates	(487)	—	—
Note receivable from affiliate	(221)	—	—
Payments received on note receivable from affiliate	55	—	—
MEP Transaction	—	—	3
Net cash provided by (used in) investing activities	(1,766)	—	3
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	2,108	92	1,858
Principal payments on debt	(162)	(20)	(1,632)
Distributions to partners	(666)	(526)	(483)
Debt issuance costs	(78)	(24)	(36)
Net cash provided by (used in) financing activities	1,202	(478)	(293)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(9)	(9)	27
CASH AND CASH EQUIVALENTS, beginning of period	18	27	—
CASH AND CASH EQUIVALENTS, end of period	$9	$18	$27