Energy Transfer Partners, L.P.
Form 10-Q
November 07, 2013
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended September 30, 2013
or

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) 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 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	¨ (Do not check if a smaller reporting company)	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

At November 1, 2013, the registrant had units outstanding as follows:
Energy Transfer Partners, L.P. 330,159,209 Common Units and 50,160,000 Class H Units.

Table of Contents

FORM 10-Q
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
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 Partners, L.P. ("Energy Transfer Partners," the "Partnership," or "ETP") in periodic press releases and some oral statements of the Partnership's officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect," "continue," "esti "goal," "forecast," "may," "will" or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see "Part I — Item 1A. Risk Factors" in the Partnership's Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission on March 1, 2013.

Definitions

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

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Bbls	barrels
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Citrus	Citrus Corp.
CrossCountry	CrossCountry Energy, LLC
DOT	U.S. Department of Transportation
ETC Compression	ETC Compression, LLC
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ET Interstate	Energy Transfer Interstate Holdings, LLC

ETP Credit Facility	ETP’s $2.5 billion revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission

Table of Contents

FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Holdco	ETP Holdco Corporation
IDRs	incentive distribution rights
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC
MGE	Missouri Gas Energy
MMBtu	million British thermal units
MTBE	methyl tertiary butyl ether
NEG	New England Gas Company
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC, a wholly-owned subsidiary of Southern Union, which owns the general partner and 100% of the limited partner interests in Panhandle Eastern Pipeline Company, LP
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission

Southern Union	Southern Union Company
SUGS	Southern Union Gas Services
Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC

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

Table of Contents

PART I — FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	September 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,064	$311
Accounts receivable, net	3,288	2,910
Accounts receivable from related companies	177	94
Inventories	1,657	1,495
Exchanges receivable	32	55
Price risk management assets	30	21
Current assets held for sale	16	184
Other current assets	318	334
Total current assets	6,582	5,404
PROPERTY, PLANT AND EQUIPMENT	27,352	27,412
ACCUMULATED DEPRECIATION	(2,262)	(1,639)
	25,090	25,773
NON-CURRENT ASSETS HELD FOR SALE	145	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,513	3,502
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	19	42
GOODWILL	5,262	5,606
INTANGIBLE ASSETS, net	1,490	1,561
OTHER NON-CURRENT ASSETS, net	455	357
Total assets	$43,556	$43,230

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

1

Table of Contents

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

	September 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,357	$3,002
Accounts payable to related companies	53	24
Exchanges payable	190	156
Price risk management liabilities	64	110
Accrued and other current liabilities	1,617	1,562
Current maturities of long-term debt	294	609
Current liabilities held for sale	13	85
Total current liabilities	5,588	5,548
NON-CURRENT LIABILITIES HELD FOR SALE	70	142
LONG-TERM DEBT, less current maturities	16,352	15,442
LONG-TERM NOTES PAYABLE — RELATED PARTY	—	166
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	54	129
DEFERRED INCOME TAXES	3,605	3,476
OTHER NON-CURRENT LIABILITIES	948	995
COMMITMENTS AND CONTINGENCIES (Note 12)		
EQUITY:		
General Partner	207	188
Limited Partners:		
Common Unitholders	12,002	9,026
Accumulated other comprehensive income (loss)	3	(13)
Total partners’ capital	12,212	9,201
Noncontrolling interest	4,727	8,131
Total equity	16,939	17,332
Total liabilities and equity	$43,556	$43,230

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

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
REVENUES:				
Natural gas sales	$721	$655	$2,286	$1,572
NGL sales	708	460	1,885	1,300
Crude sales	4,215	—	11,408	—
Gathering, transportation and other fees	648	530	1,977	1,429
Refined product sales	4,633	—	13,945	—
Other	977	157	2,806	420
Total revenues	11,902	1,802	34,307	4,721
COSTS AND EXPENSES:				
Cost of products sold	10,654	1,026	30,477	2,606
Operating expenses	331	167	950	493
Depreciation and amortization	253	162	764	419
Selling, general and administrative	138	82	424	272
Total costs and expenses	11,376	1,437	32,615	3,790
OPERATING INCOME	526	365	1,692	931
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(210)	(147)	(632)	(479)
Equity in earnings of unconsolidated affiliates	28	8	137	64
Gain on deconsolidation of Propane Business	—	—	—	1,057
Gain on sale of AmeriGas common units	87	—	87	—
Loss on extinguishment of debt	—	—	—	(115)
Gains (losses) on interest rate derivatives	—	—	46	(9)
Other, net	7	7	6	10
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	438	233	1,336	1,459
Income tax expense from continuing operations	47	27	139	36
INCOME FROM CONTINUING OPERATIONS	391	206	1,197	1,423
Income (loss) from discontinued operations	13	(142)	44	(136)
NET INCOME	404	64	1,241	1,287
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	49	28	244	25
NET INCOME ATTRIBUTABLE TO PARTNERS	355	36	997	1,262
GENERAL PARTNER’S INTEREST IN NET INCOME	146	116	429	342
LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS)	$209	$(80)	$568	$920
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:				
Basic	$0.51	$0.26	$1.55	$4.54
Diluted	$0.51	$0.26	$1.55	$4.52
NET INCOME (LOSS) PER LIMITED PARTNER UNIT:				

Basic	$0.55	$(0.33)	$1.63	$3.91
Diluted	$0.55	$(0.33)	$1.63	$3.89

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

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income	$404	$64	$1,241	$1,287
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(3)	(9)	(5)	(21)
Change in value of derivative instruments accounted for as cash flow hedges	(4)	(7)	4	14
Change in value of available-for-sale securities	1	—	1	—
Actuarial gain relating to pension and other postretirement benefits	8	—	9	—
Foreign currency translation adjustment	—	—	(1)	—
Change in other comprehensive income from equity investments	9	8	13	(14)
	11	(8)	21	(21)
Comprehensive income	415	56	1,262	1,266
Less: Comprehensive income attributable to noncontrolling interest	49	9	241	33
Comprehensive income attributable to partners	$366	$47	$1,021	$1,233

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2013
(Dollars in millions)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2012	$188	$9,026	$(13)	$8,131	$17,332
Distributions to partners	(410)	(931)	—	—	(1,341)
Distributions to noncontrolling interest	—	—	—	(309)	(309)
Units issued for cash	—	1,301	—	—	1,301
Capital contributions from noncontrolling interest	—	—	—	100	100
Holdco Acquisition and SUGS Contribution (See Note 2)	—	2,013	(5)	(3,445)	(1,437)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	28	—	9	37
Other comprehensive income (loss), net of tax	—	—	24	(3)	21
Other, net	—	(3)	(3)	—	(6)
Net income	429	568	—	244	1,241
Balance, September 30, 2013	$207	$12,002	$3	$4,727	$16,939

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

Table of Contents

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

	Nine Months Ended September 30,	
	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$1,241	$1,287
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	764	419
Deferred income taxes	249	40
Gain on curtailment of other postretirement benefits	—	(15)
Amortization of finance costs charged to interest	(63)	(9)
Loss on extinguishment of debt	—	115
LIFO valuation adjustments	(22)	—
Non-cash compensation expense	36	31
Gain on deconsolidation of Propane Business	—	(1,057)
Gain on sale of AmeriGas common units	(87)	—
Write-down of assets included in loss from discontinued operations	—	145
Distributions on unvested awards	(9)	(6)
Equity in earnings of unconsolidated affiliates	(137)	(64)
Distributions from unconsolidated affiliates	220	95
Other non-cash	11	64
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 3)	(461)	(133)
Net cash provided by operating activities	1,742	912
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for Citrus Merger	—	(1,895)
Cash proceeds from contribution and sale of propane operations	—	1,443
Cash proceeds from SUGS Contribution (See Note 2)	493	—
Cash paid for Holdco Acquisition (See Note 2)	(1,332)	—
Cash proceeds from the sale of the MGE assets (See Note 2)	973	—
Cash proceeds from the sale of AmeriGas common units	346	—
Cash (paid) received from all other acquisitions	(5)	471
Capital expenditures (excluding allowance for equity funds used during construction)	(1,840)	(1,938)
Contributions in aid of construction costs	11	28
Contributions to unconsolidated affiliates	(1)	(2)
Distributions from unconsolidated affiliates in excess of cumulative earnings	121	95
Proceeds from the sale of assets	37	13
Other	(29)	(2)
Net cash used in investing activities	(1,226)	(1,787)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	6,971	5,696
Repayments of long-term debt	(6,312)	(4,744)
Repayments of borrowings from affiliates	(166)	—
Net proceeds from issuance of Limited Partner units	1,301	772
Capital contributions received from noncontrolling interest	123	240
Distributions to partners	(1,341)	(1,020)

Distributions to noncontrolling interest	(309)	(39)
Debt issuance costs	(30)	(20)
Net cash provided by financing activities	237	885
INCREASE IN CASH AND CASH EQUIVALENTS	753	10
CASH AND CASH EQUIVALENTS, beginning of period	311	107
CASH AND CASH EQUIVALENTS, end of period	$ 1,064	$ 117

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

Table of Contents

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

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners, L.P., a publicly traded Delaware limited partnership, and its subsidiaries ("Energy Transfer Partners," the "Partnership," "we" or "ETP") are managed by ETP's general partner, ETP GP, which is in turn managed by its general partner, ETP LLC. ETE, a publicly traded master limited partnership, owns ETP LLC, the general partner of our General Partner. The consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

Business Operations

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

- 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. ETC OLP's intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP's midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Sunoco Logistics, 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, a Delaware limited liability company that indirectly owns Southern Union and Sunoco. As discussed in Note 2, ETP acquired ETE's 60% interest in Holdco on April 30, 2013. Sunoco and Southern Union 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 transportation, storage and distribution of natural gas in the United States. As discussed in Note 2, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interests in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. Additionally, as discussed in Note 2, on September 1, 2013, Southern Union completed its sale of the assets of MGE to Laclede Gas Company.
- Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores primarily on the east coast and in the midwest region of the United States.

Our financial statements reflect the following reportable business segments:

- intrastate natural gas transportation and storage;

Table of Contents

- interstate natural gas transportation and storage;
- midstream;
- NGL transportation and services;
- investment in Sunoco Logistics; and
- retail marketing.

Preparation of Interim Financial Statements

The accompanying consolidated balance sheet as of December 31, 2012, which has been derived from audited financial statements, and the unaudited interim consolidated financial statements and notes thereto of the Partnership as of September 30, 2013 and for the three and nine month periods ended September 30, 2013 and 2012, have been prepared in accordance with GAAP for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of the Partnership as of September 30, 2013, and the Partnership's results of operations and cash flows for the three and nine months ended September 30, 2013 and 2012. The unaudited interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012, as filed with the SEC on March 1, 2013.

Certain prior period amounts have been reclassified to conform to the 2013 presentation. These reclassifications had no impact on net income or total equity.

In accordance with GAAP, we have accounted for the October 2012 transaction in which ETE contributed its interest in Southern Union to Holdco in exchange for a 60% interest in Holdco and ETP contributed its interest in Sunoco (exclusive of Sunoco Logistics) to Holdco in exchange for a 40% interest in Holdco (the "Holdco Transaction") as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect the consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union).

2. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

Sale of Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri agreed to acquire the assets of Southern Union's MGE division and Laclede Massachusetts agreed to acquire the assets of Southern Union's NEG division (together, the "LDC Disposal Group"). Laclede Gas Company, a subsidiary of The Laclede Group, Inc., subsequently assumed all of Laclede Missouri's rights and obligations under the purchase and sale agreement. In February 2013, The Laclede Group, Inc. entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that allows a subsidiary of APUC to assume the rights of The Laclede Group, Inc. to purchase the assets of Southern Union's NEG division, subject to certain approvals. Effective September 1, 2013, Southern Union completed its sale of the assets of MGE to Laclede Gas Company for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. The sale of Southern Union's NEG division is expected to close in the fourth quarter of 2013 for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

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

SUGS Contribution

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

Contribution”). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction

8

Table of Contents

consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings, a wholly-owned subsidiary of Southern Union, provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. The Partnership has not presented SUGS as discontinued operations due to the expected continuing involvement with SUGS through affiliate relationships, as well as the direct investment in Regency common and Class F units received, which has been accounted for using the equity method.

Acquisition of ETE's Holdco Interest

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

Sunoco Merger

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco (the "Sunoco Merger"). Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 55 million ETP Common Units and $2.6 billion in cash.

3. CASH AND CASH EQUIVALENTS:

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

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

	Nine Months Ended September 30, 2013	2012
Accounts receivable	$(392)	$(67)
Accounts receivable from related companies	(50)	(44)
Inventories	(132)	(56)
Exchanges receivable	—	22
Other current assets	(186)	67
Other non-current assets, net	(29)	(32)
Accounts payable	398	43
Accounts payable to related companies	(67)	99
Exchanges payable	36	(24)
Accrued and other current liabilities	92	(154)
Other non-current liabilities	(15)	(3)
Price risk management assets and liabilities, net	(116)	16
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$(461)	$(133)

9

Table of Contents

Non-cash investing and financing activities are as follows:

	Nine Months Ended September 30,	
	2013	2012
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$190	$391
AmeriGas limited partner interests received in exchange for contribution of Propane Business	$—	$1,123
Regency common and Class F units received in exchange for contribution of SUGS	$961	$—
NON-CASH FINANCING ACTIVITIES:		
Contributions receivable related to noncontrolling interest	$—	$13
Issuance of common units in connection with acquisitions	$—	$112
Issuance of common units in connection with the Holdco Acquisition	$2,464	$—

4. INVENTORIES:

Inventories consisted of the following:

	September 30, 2013	December 31, 2012
Natural gas and NGLs	$509	$334
Crude oil	464	418
Refined products	517	572
Appliances, parts and fittings and other	167	171
Total inventories	$1,657	$1,495

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory and designate certain of these derivatives as fair value hedges for accounting purposes. Changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheets and in cost of products sold in our consolidated statements of operations.

5. FAIR VALUE MEASUREMENTS:

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements, and we discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the nine months ended September 30, 2013, no transfers were made between any levels within the fair value hierarchy.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value of our consolidated debt obligations at September 30, 2013 and December 31, 2012 was $17.16 billion and $17.84 billion, respectively. As of September 30, 2013 and December 31, 2012, the aggregate carrying amount of our consolidated debt obligations was $16.65 billion and $16.22 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 September 30, 2013 and December 31, 2012 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at September 30, 2013	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$43	$—	$43
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	4	4	—
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	84	84	—
Options — Calls	1	—	1
Forward Physical Swaps	1	—	1
Power — Forwards	2	—	2
Natural Gas Liquids — Forwards/Swaps	9	9	—
Refined Products — Futures	25	25	—
Total commodity derivatives	127	122	5
Total Assets	$170	$122	$48
Liabilities:			
Interest rate derivatives	$(111)	$—	$(111)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(8)	(8)	—
Swing Swaps IFERC	(2)	—	(2)
Fixed Swaps/Futures	(58)	(58)	—
Options — Calls	(1)	—	(1)
Power:			
Forwards	(1)	—	(1)
Options — Calls	(2)	—	(2)
Natural Gas Liquids — Forwards/Swaps	(8)	(8)	—
Refined Products — Futures	(16)	(16)	—
Crude — Futures	(2)	(2)	—
Total commodity derivatives	(98)	(92)	(6)
Total Liabilities	$(209)	$(92)	$(117)

Table of Contents

	Fair Value Total	Fair Value Measurements at December 31, 2012	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$55	$—	$55
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	11	11	—
Swing Swaps IFERC	3	—	3
Fixed Swaps/Futures	96	94	2
Options — Puts	1	—	1
Options — Calls	3	—	3
Forward Physical Swaps	1	—	1
Power:			
Forwards	27	—	27
Futures	1	1	—
Options — Calls	2	—	2
Natural Gas Liquids — Swaps	1	1	—
Refined Products — Futures	5	1	4
Total commodity derivatives	151	108	43
Total Assets	$206	$108	$98
Liabilities:			
Interest rate derivatives	$(223)	$—	$(223)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(18)	(18)	—
Swing Swaps IFERC	(2)	—	(2)
Fixed Swaps/Futures	(103)	(94)	(9)
Options — Puts	(1)	—	(1)
Options — Calls	(3)	—	(3)
Power:			
Forwards	(27)	—	(27)
Futures	(2)	(2)	—
Natural Gas Liquids — Swaps	(3)	(3)	—
Refined Products — Futures	(8)	(1)	(7)
Total commodity derivatives	(167)	(118)	(49)
Total Liabilities	$(390)	$(118)	$(272)

6. NET INCOME PER LIMITED PARTNER UNIT:

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

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Income from continuing operations	$391	$206	$1,197	$1,423
Less: Income from continuing operations attributable to noncontrolling interest	49	22	227	10
Income from continuing operations, net of noncontrolling interest	342	184	970	1,413
General Partner’s interest in income from continuing operations	146	119	428	344
Limited Partners’ interest in income from continuing operations	196	65	542	1,069
Additional earnings allocated from (to) General Partner	—	1	(1)	1
Distributions on employee unit awards, net of allocation to General Partner	(3)	(2)	(8)	(9)
Income from continuing operations available to Limited Partners	$193	$64	$533	$1,061
Weighted average Limited Partner units – basic	374.1	245.1	342.8	233.8
Basic income from continuing operations per Limited Partner unit	$0.51	$0.26	$1.55	$4.54
Dilutive effect of unvested Unit Awards	1.4	1.2	1.3	1.2
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	375.5	246.3	344.1	235.0
Diluted income from continuing operations per Limited Partner unit	$0.51	$0.26	$1.55	$4.52
Basic income (loss) from discontinued operations per Limited Partner unit	$0.04	$(0.59)	$0.08	$(0.63)
Diluted income (loss) from discontinued operations per Limited Partner unit	$0.04	$(0.59)	$0.08	$(0.63)

7. DEBT OBLIGATIONS:

Senior Notes

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

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

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

Note Exchange

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

Table of Contents

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

Credit Facilities

ETP Credit Facility

ETP has a $2.5 billion revolving credit facility which expires in October 2016. Indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The ETP Credit Facility had no outstanding borrowings as of September 30, 2013.

Southern Union Credit Facility

Proceeds from the SUGS Contribution were used to repay $240 million of borrowings under the Eighth Amended and Restated Revolving Credit Agreement (the "Southern Union Credit Facility") and the facility was terminated.

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 and a $200 million unsecured credit facility which expires in August 2014. There were no outstanding borrowings under these credit facilities as of September 30, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility which expires in April 2015. Outstanding borrowings under this credit facility were $35 million as of September 30, 2013.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2013.

8. EQUITY:

Class G Units

In April 2013, all of the outstanding ETP Class F Units, which were issued in connection with the Sunoco Merger, were exchanged for ETP Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are held by a subsidiary and therefore are reflected as treasury units in the consolidated financial statements.

Class H Units

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

14

Table of Contents

Common Unit Activity

The change in Common Units during the nine months ended September 30, 2013 was as follows:

	Number of Units
Outstanding at December 31, 2012	301.5
Common Units issued in connection with public offerings	13.8
Common Units issued in connection with Equity Distribution Agreements	11.6
Common Units issued in connection with the Distribution Reinvestment Plan	1.6
Common Units issued in connection with the Holdco Acquisition	49.5
Outstanding at September 30, 2013	378.0

In January 2013 and May 2013, we entered into Equity Distribution Agreements pursuant to which we may sell from time to time Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the nine months ended September 30, 2013, we received proceeds of $568 million, net of commissions of $6 million, from the issuance of units pursuant to the Equity Distribution Agreements, which proceeds were used for general partnership purposes. We also received $13 million, net of commissions, in October 2013 from the settlement of transactions initiated in September 2013 under these agreements. Approximately $426 million of our Common Units remain available to be issued under these agreements.

During the nine months ended September 30, 2013, distributions of $76 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 1.6 million Common Units. As of September 30, 2013, a total of 2.7 million Common Units remain available to be issued under the existing registration statement.

In April 2013, we issued 13.8 million Common Units at $48.05 per Common Unit in an underwritten public offering. Net proceeds of $657 million from the offering were used to repay amounts outstanding under the ETP Credit Facility and for general partnership purposes.

As discussed in “Class H Units” above ETP redeemed and cancelled 50.2 million of its Common Units in connection with the issuance of Class H Units to ETE.

Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by ETP subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 7, 2013	February 14, 2013	$0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375
June 30, 2013	August 5, 2013	August 14, 2013	0.89375
September 30, 2013	November 4, 2013	November 14, 2013	0.90500

Following are incentive distributions ETE has agreed to relinquish:

- In conjunction with the Partnership’s Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.
- As discussed in Note 2, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.
- As discussed under “Class H Units” above, ETP has agreed to make incremental cash distributions in the aggregate amount of $329 million to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and

Table of Contents

ending with the quarter ending March 31, 2017, in respect of the Class H units as a means to offset prior IDR subsidies that ETE agreed to in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition.

As a result, the net IDR subsidies from ETE, taking into account the incremental cash distributions related to the Class H units as an offset thereto, will be the amounts set forth in the table below:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2013	N/A	N/A	$21.00	$21.00	$42.00
2014	$27.25	$27.25	27.25	27.25	109.00
2015	13.25	13.25	13.25	13.25	53.00
2016	5.50	5.50	5.50	5.50	22.00

Sunoco Logistics Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2012:

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

Accumulated Other Comprehensive Income (Loss)

The following table presents the components of accumulated other comprehensive income (loss), net of tax:

	September 30, 2013	December 31, 2012
Available-for-sale securities	$1	$—
Foreign currency translation adjustment	(1)	—
Actuarial loss related to pensions and other postretirement benefits	(1)	(10)
Equity investments, net	4	(9)
Subtotal	3	(19)
Amounts attributable to noncontrolling interest	—	6
Total accumulated other comprehensive income (loss), net of tax	$3	$(13)

9. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plans

During the nine months ended September 30, 2013, employees were granted a total of 1,142,663 unvested awards with five-year service vesting requirements, and directors were granted a total of 9,060 unvested awards with three-year and five-year service vesting requirements. The weighted average grant-date fair value of these awards was $45.74 per unit. As of September 30, 2013, a total of 2,840,725 unit awards remain unvested, for which we expect to recognize $72 million in compensation expense over a weighted average period of 1.8 years related to unvested awards.

Sunoco Logistics' Unit-Based Compensation Plan

As of September 30, 2013, a total of 918,031 Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $16 million in compensation expense over a weighted-average period of 2.4 years.

Table of Contents

10. INCOME TAXES:

The follow table summarizes the Partnership's income tax expense from continuing operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Income tax expense from continuing operations	$47	$27	$139	$36
Effective tax rate	11 %	12 %	10 %	2 %

The increase in the effective tax rate for the nine months ended September 30, 2013 compared to the same period last year is primarily due to the Partnership conducting a significant portion of its activities through its corporate subsidiaries, Southern Union and Sunoco, as a result of the Holdco Transaction and Sunoco Merger completed in 2012.

Sunoco has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco's 2004 through 2011 open statute years, Sunoco has proposed to the Internal Revenue Service ("IRS") that these government incentive payments be excluded from federal taxable income. A successful claim could result in significant tax refunds for multiple years. However, a thorough evaluation of the ultimate financial impact to Sunoco is complex and requires significant analysis, including the ramifications of tax indemnification agreements with certain former Sunoco affiliates which were members of Sunoco's consolidated federal return group during these years. At this time, a benefit for the claim is not estimable and has not been recorded in the financial statements.

11. RETIREMENT BENEFITS:

The following tables set forth the components of net period benefit cost of the Partnership's pension and other postretirement benefit plans:

	Three Months Ended September 30,			
	2013		2012[1]	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$—	$(1)	$1	$—
Interest cost	10	2	2	1
Expected return on plan assets	(15)	(3)	(3)	(2)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	1	—	—	—
	(4)	(1)	—	(1)
Regulatory adjustment[2]	1	—	3	1
Net periodic benefit cost	$(3)	$(1)	$3	$—

Table of Contents

	Nine Months Ended September 30,			
	2013		2012[1]	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$5	$—	$2	$—
Interest cost	28	5	5	1
Expected return on plan assets	(45)	(7)	(6)	(3)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	2	—	—	—
Settlement credits	(2)	—	—	—
Curtailment recognition[3]	—	—	—	(15)
	(12)	(1)	1	(17)
Regulatory adjustment[2]	5	—	6	1
Net periodic benefit cost	$(7)	$(1)	$7	$(16)

(1) The three and nine months ended September 30, 2012 include components of net periodic benefit cost of Southern Union subsequent to the Southern Union Merger on March 26, 2012.

(2) Southern Union has historically recovered certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers in its MGE and NEG divisions. 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.

(3) 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.

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

FERC Audit

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

Contingent Residual Support Agreement — AmeriGas

In connection with the closing of the contribution of its propane operations in January 2013, ETP agreed to provide contingent, residual support of $1.55 billion of senior notes issued by AmeriGas and certain of its affiliates with maturities through 2022.

PEPL Holdings Guarantee of Collection

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

Commitments

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

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled $31 million and $12 million for the three months ended September 30, 2013 and 2012, respectively, which include contingent rentals totaling $8 million in the three months ended September 30, 2013. For the nine months ended September 30, 2013 and 2012, rental expense for operating leases totaled $93 million and $29 million, respectively, which include contingent rentals totaling $18 million in the nine months ended September 30, 2013. During the three and nine months ended September 30, 2013, $6 million and $16 million, respectively, of rental expense was recovered through related sublease rental income.

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

Litigation and Contingencies

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

Sunoco Litigation

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

Litigation Relating to the Southern Union Merger

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

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

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

MTBE Litigation

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

As of September 30, 2013, Sunoco is a defendant in six cases, including one initiated by the State of New Jersey and another by the Commonwealth of Puerto Rico. These cases are venued in a multidistrict proceeding in a New York federal court. The two state 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 an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership's consolidated financial position.

Other Litigation and Contingencies

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

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of September 30, 2013 and December 31, 2012, accruals of approximately $38 million and $42 million, respectively, were reflected on our balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

No amounts have been recorded in our September 30, 2013 or December 31, 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Litigation Related to Incident at JJ's Restaurant. On February 19, 2013, there was a natural gas explosion at JJ's Restaurant located at 910 W. 48th Street in Kansas City, Missouri. Effective September 1, 2013, Laclede Gas Company, a subsidiary of The Laclede Group, Inc. ("Laclede"), assumed any and all liability arising from this incident in ETP's sale of the assets of MGE to Laclede.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General ("AG") filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, the Southern Union former Vice Chairman, President and Chief Operating Officer, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. 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.

Environmental Matters

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

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

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

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 manufactured gas plants ("MGPs") and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party ("PRP"). As of September 30, 2013, Sunoco had been named as a PRP at 39 identified or potentially identifiable as "Superfund" sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco's purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

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

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

	September 30, 2013	December 31, 2012
Current	$38	$46
Non-current	185	165
Total environmental liabilities	$223	$211

During the three and nine months ended September 30, 2013, Sunoco recorded $8 million and $23 million, respectively, of expenditures related to environmental cleanup programs.

The EPA's Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

On August 20, 2010, the EPA published new regulations under the federal Clean Air Act ("CAA") to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule was required by October 2013, and the Partnership believes it is in compliance.

Table of Contents

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule's requirements, because the rule applies only to changes we might make in the future.
Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.
Our operations are also subject to the requirements of the OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.
We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.
We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent

the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate

Table of Contents

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.

Table of Contents

The following table details our outstanding commodity-related derivatives:

	September 30, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	6,560,000	2013-2019	—	—
Basis Swaps IFERC/NYMEX[(1)]	(27,402,500)	2013-2017	(30,980,000)	2013-2014
Swing Swaps	1,690,000	2013-2016	—	—
Power (Megawatt):				
Forwards	562,250	2013	19,650	2013
Futures	97,212	2013	(1,509,300)	2013
Options — Calls	(1,700)	2013	1,656,400	2013
Crude (Bbls) — Futures	80,000	2013	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(5,300,000)	2013-2014	150,000	2013
Swing Swaps IFERC	6,965,000	2013-2016	(83,292,500)	2013
Fixed Swaps/Futures	(14,072,500)	2013-2015	27,077,500	2013
Forward Physical Contracts	(11,663,485)	2013-2014	11,689,855	2013-2014
Natural Gas Liquid (Bbls) — Forwards/Swaps	(1,182,000)	2013-2014	(30,000)	2013
Refined Products (Bbls) — Futures	(93,327)	2013-2014	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(6,577,500)	2013	(18,655,000)	2013
Fixed Swaps/Futures	(47,215,000)	2014	(44,272,500)	2013
Hedged Item — Inventory	47,215,000	2014	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,150,000)	2013	—	—
Fixed Swaps/Futures	(5,720,000)	2013	(8,212,500)	2013
Natural Gas Liquid (Bbls) — Forwards/Swaps	(720,000)	2013	(930,000)	2013
Refined Products (Bbls) — Futures	—	—	(98,000)	2013
Crude (Bbls) — Futures	(120,000)	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 gains of $1 million related to 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.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps

Table of Contents

to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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

Entity	Term	Type[(1)]	Notional Amount Outstanding September 30, 2013	December 31, 2012
ETP	July 2013[(2)]	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$—	$400
ETP	July 2014[(2)]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.15% and receive a fixed rate of 4.65%	200	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	25	75
Southern Union	November 2021	Pay a fixed rate of 3.75% and receive a floating rate	450	450

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

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date. During the nine months ended September 30, 2013, we settled $400 million of ETP’s forward-starting interest rate swaps that had an effective date of July 2013.

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 exposure associated with a single or multiple counterparties.

Our counterparties consist of a diverse portfolio of customers across the energy industry including petrochemical companies, consumer and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure to credit risk may be affected either positively or negatively in that the counterparties may experience similar 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.

We utilize 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 our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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

Table of Contents

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$16	$8	$(3)	$(10)
	16	8	(3)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	112	110	(95)	(116)
Commodity derivatives	32	33	(33)	(34)
Current assets held for sale	—	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	—	(9)
Interest rate derivatives	43	55	(111)	(223)
	187	200	(239)	(382)
Total derivatives	$203	$208	$(242)	$(392)

In addition to the above derivatives, $7 million in option premiums were included in price risk management liabilities as of December 31, 2012.

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$37	$28	$(38)	$(27)
Broker cleared derivative contracts	Other current assets (liabilities)	170	150	(159)	(228)
		207	178	(197)	(255)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	2
Counterparty netting	Price risk management assets (liabilities)	(32)	(25)	32	25
Payments on margin deposit	Other current assets	(15)	—	34	59
		(47)	(25)	66	86
Net derivatives with offsetting agreements		160	153	(131)	(169)
Derivatives without offsetting agreements		43	55	(111)	(223)
Total derivatives		$203	$208	$(242)	$(392)

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:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$(4)	$(7)	$4	$14
Total	$(4)	$(7)	$4	$14

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$3	$9	$5	$21
Total		$3	$9	$5	$21

	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			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$—	$4	$4	$29
Total		$—	$4	$4	$29

Table of Contents

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$(11)	$4	$(12)	$(7)
Commodity derivatives – Non-Trading	Cost of products sold	(23)	(5)	(20)	(13)
Commodity derivatives – Non-Trading	Deferred gas purchases	—	—	(3)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	—	—	46	(9)
Total		$(34)	$(1)	$11	$(29)

14. RELATED PARTY TRANSACTIONS:

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and on behalf of other subsidiaries of ETE, which includes the reimbursement of various general and administrative services for expenses incurred by us on behalf of Regency.

In the ordinary course of business, we provide Regency with certain natural gas and NGLs sales and transportation services and compression equipment, and Regency provides us with certain contract compression services. These related party transactions are generally based on transactions made at market-related rates.

Sunoco Logistics has an agreement with PES relating to the Fort Mifflin Terminal Complex. Under this agreement, PES will deliver an average of 300,000 Bbls/d of crude oil and refined products per contract year at the Fort Mifflin facility. PES does not have exclusive use of the Fort Mifflin Terminal Complex; however, Sunoco Logistics is obligated to provide the necessary tanks, marine docks and pipelines for PES to meet its minimum requirements under the agreement. Sunoco Logistics executed a 10-year agreement with PES in September 2012.

In September 2012, Sunoco assigned its lease for the use of Sunoco Logistics' inter-refinery pipelines between the Philadelphia and Marcus Hook refineries to PES. Under the 20-year lease agreement which expires in February 2022, PES leases the inter-refinery pipelines for an annual fee which escalates at 1.67% each January 1 for the term of the agreement. The lease agreement also requires PES to reimburse Sunoco Logistics for any non-routine maintenance expenditures, as defined, incurred during the term of the agreement. There were no material reimbursements under this agreement during 2010 through 2012.

The following table summarizes the affiliate revenue on our consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Affiliated revenue	$439	$20	$1,154	$37

Table of Contents

The following table summarizes the related company balances on our consolidated balance sheets:

	September 30, 2013	December 31, 2012
Accounts receivable from related companies:		
ETE	$29	$16
Regency	75	10
PES	20	60
FGT	19	2
Other	34	6
Total accounts receivable from related companies:	$177	$94
Accounts payable to related companies:		
ETE	$8	$7
Regency	35	2
PES	4	13
FGT	3	—
Other	3	2
Total accounts payable to related companies:	$53	$24

15. OTHER INFORMATION:

The following tables present additional detail for certain balance sheet captions.

Other Current Assets

Other current assets consisted of the following:

	September 30, 2013	December 31, 2012
Deposits paid to vendors	$55	$41
Prepaid expenses and other	263	293
Total other current assets	$318	$334

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	September 30, 2013	December 31, 2012
Interest payable	$232	$256
Customer advances and deposits	55	44
Accrued capital expenditures	187	356
Accrued wages and benefits	181	236
Taxes payable other than income taxes	276	203
Income taxes payable	82	40
Deferred income taxes	243	130
Deferred revenue	2	—
Other	359	297
Total accrued and other current liabilities	$1,617	$1,562

Table of Contents

16. REPORTABLE SEGMENTS:

As a result of the Sunoco Merger and Holdco Transaction, our reportable segments were re-evaluated and changed in 2012. Our financial statements currently reflect six reportable segments, which conduct their business exclusively in the United States, as follows:

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

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our investment in Sunoco Logistics segment are primarily reflected in crude sales. Revenues from our retail marketing segment are primarily reflected in refined product sales.

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities 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. Previously, amounts for less than wholly owned subsidiaries were reflected in Segment Adjusted EBITDA based on the Partnership’s proportionate ownership, such that the measure was reduced for amounts attributable to noncontrolling interests. During the three months ended December 31, 2012, management changed its definition of Segment Adjusted EBITDA to reflect amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries’ results of operations. Management believes that the revised segment performance measure more closely reflects the presentation of less than wholly owned subsidiaries within the Partnership’s consolidated financial statements. For periods prior to the three months ended December 31, 2012, only the NGL transportation and services segment included a less than wholly owned subsidiary. Based on this change in our definition of Segment Adjusted EBITDA, we have recast the presentation of our segment results for 2012 to be consistent with the current year presentation.

The following tables present the financial information by segment:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$502	$503	$1,711	$1,402
Intersegment revenues	51	53	155	130
	553	556	1,866	1,532
Interstate transportation and storage:				
Revenues from external customers	296	309	973	761
Intersegment revenues	15	12	19	14
	311	321	992	775
Midstream:				
Revenues from external customers	683	757	2,021	1,845
Intersegment revenues	256	107	775	309
	939	864	2,796	2,154
NGL transportation and services:				
Revenues from external customers	537	157	1,303	459
Intersegment revenues	11	11	48	37
	548	168	1,351	496
Investment in Sunoco Logistics:				
Revenues from external customers	4,502	—	12,215	—
Intersegment revenues	26	—	136	—
	4,528	—	12,351	—
Retail marketing:				
Revenues from external customers	5,297	—	15,805	—
Intersegment revenues	1	—	6	—
	5,298	—	15,811	—
All other:				
Revenues from external customers	85	76	279	254
Intersegment revenues	10	28	67	65
	95	104	346	319
Eliminations	(370)	(211)	(1,206)	(555)
Total revenues	$11,902	$1,802	$34,307	$4,721

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$108	$121	$352	$470
Interstate transportation and storage	310	324	968	701
Midstream	125	134	322	335
NGL transportation and services	100	50	257	155
Investment in Sunoco Logistics	181	—	661	—
Retail marketing	100	—	234	—
All other	18	31	173	135
Total	942	660	2,967	1,796
Depreciation and amortization	(253)	(162)	(764)	(419)
Interest expense, net of interest capitalized	(210)	(147)	(632)	(479)
Gain on deconsolidation of Propane Business	—	—	—	1,057
Gain on sale of AmeriGas common units	87	—	87	—
Gains (losses) on interest rate derivatives	—	—	46	(9)
Non-cash unit-based compensation expense	(12)	(10)	(36)	(31)
Unrealized gains (losses) on commodity risk management activities	8	11	45	(60)
LIFO valuation adjustments	6	—	22	—
Loss on extinguishment of debt	—	—	—	(115)
Adjusted EBITDA attributable to discontinued operations	(12)	(32)	(75)	(66)
Adjusted EBITDA related to unconsolidated affiliates	(151)	(106)	(474)	(302)
Equity in earnings of unconsolidated affiliates	28	8	137	64
Other, net	5	11	13	23
Income from continuing operations before income tax expense	$438	$233	$1,336	$1,459

	September 30, 2013	December 31, 2012
Total assets:		
Intrastate transportation and storage	$4,613	$4,691
Interstate transportation and storage	11,589	11,794
Midstream	3,339	5,098
NGL transportation and services	4,218	3,765
Investment in Sunoco Logistics	11,308	10,291
Retail marketing	3,734	3,926
All other	4,755	3,665
Total	$43,556	$43,230

Table of Contents

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; (ii) our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the SEC on March 1, 2013; and (iii) our management's discussion and analysis of financial condition and results of operations included in our 2012 Form 10-K. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Part I – Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2012.

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

OVERVIEW

The activities and the wholly-owned operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and 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.
- Other operations, including the following:
  - natural gas compression services through ETC Compression;
  - a limited partner interest in AmeriGas;
  - natural gas distribution operations through Southern Union;
  - an approximate 30% non-operating interest in a refining joint venture; and
  - a limited partner interest in Regency.

RECENT DEVELOPMENTS

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes. The fair value on the settlement date of the 7.6% Senior Notes due 2024, the 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066 was $328 million, $328 million and $464 million, respectively, which represented 118.16%, 122.84% and 85%, respectively, of the outstanding principal amount of the notes.

Sale of AmeriGas Common Units

On July 12, 2013, the Partnership received $346 million in net proceeds from the sale of 7.5 million of its AmeriGas common units, which were received in connection with the Partnership's contribution of its retail propane operations to AmeriGas in January 2012. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility.

Table of Contents

Class H Units

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

ETP agreed to make incremental cash distributions of $329 million discussed above as a means to offset prior IDR subsidies that ETE agreed to in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. As a result, the net IDR subsidies from ETE to ETP, taking into account the incremental cash distributions related to the Class H Units as an offset thereto, were $21 million for the quarter ended September 30, 2013 and will be $21 million with respect to the quarter ending December 31, 2013, a total of $109 million during 2014, a total of $53 million during 2015 and a total of $22 million during 2016.

LNG Export License

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

Sale of Distribution Operations

Effective September 1, 2013, Southern Union completed its sale of the assets of MGE to Laclede Gas Company for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. The sale of Southern Union’s NEG division is expected to close in the fourth quarter of 2013 for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

Retail Acquisition

In October 2013, La Grange Acquisition, L.P., an indirect wholly-owned subsidiary of ETP, acquired a convenience store operator with a network of approximately 300 company-owned and dealer locations for approximately $400 million in cash. These operations will be reflected in ETP’s retail marketing segment, along with the retail marketing operations owned by Holdco, beginning in the fourth quarter of 2013.

Table of Contents

Results of Operations
Consolidated Results

	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$108	$121	$(13)	$352	$470	$(118)
Interstate transportation and storage	310	324	(14)	968	701	267
Midstream	125	134	(9)	322	335	(13)
NGL transportation and services	100	50	50	257	155	102
Investment in Sunoco Logistics	181	—	181	661	—	661
Retail marketing	100	—	100	234	—	234
All other	18	31	(13)	173	135	38
Total	942	660	282	2,967	1,796	1,171
Depreciation and amortization	(253)	(162)	(91)	(764)	(419)	(345)
Interest expense, net of interest capitalized	(210)	(147)	(63)	(632)	(479)	(153)
Gain on deconsolidation of Propane Business	—	—	—	—	1,057	(1,057)
Gain on sale of AmeriGas common units	87	—	87	87	—	87
Gains (losses) on interest rate derivatives	—	—	—	46	(9)	55
Non-cash unit-based compensation expense	(12)	(10)	(2)	(36)	(31)	(5)
Unrealized gains (losses) on commodity risk management activities	8	11	(3)	45	(60)	105
LIFO valuation adjustments	6	—	6	22	—	22
Loss on extinguishment of debt	—	—	—	—	(115)	115
Adjusted EBITDA attributable to discontinued operations	(12)	(32)	20	(75)	(66)	(9)
Adjusted EBITDA related to unconsolidated affiliates	(151)	(106)	(45)	(474)	(302)	(172)
Equity in earnings of unconsolidated affiliates	28	8	20	137	64	73
Other, net	5	11	(6)	13	23	(10)
Income from continuing operations before income tax expense	438	233	205	1,336	1,459	(123)
Income tax expense from continuing operations	(47)	(27)	(20)	(139)	(36)	(103)
Income from continuing operations	391	206	185	1,197	1,423	(226)
Income (loss) from discontinued operations	13	(142)	155	44	(136)	180
Net income	$404	$64	$340	$1,241	$1,287	$(46)

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased for the three months ended September 30, 2013 compared to the same period last year primarily due to:

- depreciation and amortization related to Sunoco Logistics and Sunoco of $95 million; and

Table of Contents

- additional depreciation and amortization related to assets placed in service; offset by
- a decrease of $25 million related to the contribution of SUGS to Regency on April 30, 2013.

Depreciation and amortization increased for the nine months ended September 30, 2013 compared to the same period last year primarily due to:

- depreciation and amortization related to Sunoco Logistics and Sunoco of $277 million;
- depreciation and amortization related to Southern Union, which was consolidated beginning March 26, 2012 and resulted in increased depreciation and amortization of $10 million after taking into account the contribution of SUGS on April 30, 2013; and
- additional depreciation and amortization related to assets placed in service.

Interest Expense. Interest expense increased for the three months ended September 30, 2013 compared to the same period last year primarily due to:

- interest expense related to Sunoco Logistics and Sunoco of $30 million; and
- incremental interest expense due to the issuance by ETP of $1.25 billion of Senior Notes in January 2013 and the issuance by ETP of $1.5 billion of Senior Notes in September 2013.

Interest expense increased for the nine months ended September 30, 2013 compared to the same period last year primarily due to:

- interest expense related to Sunoco Logistics and Sunoco of $83 million; and
- incremental interest expense due to the issuance by ETP of $1.25 billion of Senior Notes in January 2013 and the issuance by ETP of $1.5 billion of Senior Notes in September 2013, offset by a reduction of several series of our higher coupon notes that were repurchased in the tender offers completed in January 2012.

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

Gain on Sale of AmeriGas Common Units. In July 2013, we sold 7.5 million of the AmeriGas common units that we originally received in connection with the contribution of our Propane Business to AmeriGas.

Gains (Losses) on Interest Rate Derivatives. For the three months ended September 30, 2013, offsetting gains and losses on non-hedged interest rate derivatives aggregated to less than $1 million. Gains on interest rate derivatives during the nine months ended September 30, 2013 resulted from increases in forward interest rates, which caused our forward-starting swaps to increase in value. These swaps are marked to fair value for accounting purposes with changes in value recorded in earnings each period. Conversely, decreases in forward interest rates resulted in losses on interest rate derivatives during the nine months ended September 30, 2012.

Unrealized Gains (Losses) on Commodity Risk Management Activities. See discussion of the unrealized gains (losses) on commodity risk management activities included in “Segment Operating Results” below.

LIFO Valuation Adjustments. LIFO valuation reserve adjustments were recorded during the three and nine months ended September 30, 2013 for the inventory associated with Sunoco’s retail marketing operations as a result of commodity price changes between periods.

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized for the nine months ended September 30, 2012 in connection with our repurchase of $750 million of Senior Notes in January 2012.

Adjusted EBITDA Attributable to Discontinued Operations. Amounts reflect the operations of Canyon, which was sold in October 2012, and Southern Union’s local distribution operations beginning March 26, 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. See additional information in “Supplemental Information on Unconsolidated Affiliates” and “Segment Operating Results” below. Our investments in AmeriGas and Citrus are only reflected for a partial period during the nine months ended September 30, 2012.

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

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

Table of Contents

Supplemental Pro Forma Financial Information

The following unaudited pro forma consolidated financial information of ETP has been prepared in accordance with Article 11 of Regulation S-X and reflects the pro forma impacts of the Propane Transaction, the Sunoco Merger and the Holdco Transaction for the nine months ended September 30, 2012 giving effect that each occurred on January 1, 2012. This unaudited pro forma financial information is provided to supplement the discussion and analysis of the historical financial information and should be read in conjunction with such historical financial information. This unaudited pro forma information is for illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Propane Transaction, the Sunoco Merger and the Holdco Transaction had been consummated on January 1, 2012.

The following table presents pro forma financial information for the nine months ended September 30, 2012:

	ETP Historical	Propane Transaction (a)	Sunoco Historical (b)	Southern Union Historical (c)	Holdco Pro Forma Adjustments (d)	Pro Forma
REVENUES	$4,721	$(93)	$35,258	$443	$(12,175)	$28,154
COSTS AND EXPENSES:						
Cost of products sold and natural gas operations	3,099	(80)	33,142	313	(11,189)	25,285
Depreciation and amortization	419	(4)	168	49	73	705
Selling, general and administrative	272	(1)	459	—	(69)	661
Impairment charges	—	—	124	—	(22)	102
Total costs and expenses	3,790	(85)	33,893	362	(11,207)	26,753
OPERATING INCOME	931	(8)	1,365	81	(968)	1,401
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(479)	2	(123)	(50)	6	(644)
Equity in earnings of affiliates	64	3	41	16	21	145
Gain on deconsolidation of Propane Business	1,057	(1,057)	—	—	—	—
Gain on formation of PES	—	—	1,144	—	(1,144)	—
Gain (loss) on disposal of assets	(1)	2	112	—	(2)	111
Loss on extinguishment of debt	(115)	115	—	—	—	—
Losses on interest rate derivatives	(9)	—	—	—	—	(9)
Other, net	11	1	6	(2)	—	16
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,459	(942)	2,545	45	(2,087)	1,020
Income tax expense from continuing operations	36	—	956	12	(931)	73
INCOME FROM CONTINUING OPERATIONS	$1,423	$(942)	$1,589	$33	$(1,156)	$947

(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 long-term debt.

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

Table of Contents

(c) Southern Union historical amounts in 2012 include 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 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.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Change	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	Change
Equity in earnings (losses) of unconsolidated affiliates:						
AmeriGas	$(19)	$(32)	$13	$24	$(29)	$53
Citrus	28	25	3	66	49	17
FEP	14	15	(1)	41	41	—
Regency	8	—	8	10	—	10
Other	(3)	—	(3)	(4)	3	(7)
Total equity in earnings of unconsolidated affiliates	$28	$8	$20	$137	$64	$73
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:						
AmeriGas	$28	$36	$(8)	$98	$108	$(10)
Citrus	57	56	1	160	113	47
FEP	6	5	1	16	16	—
Regency	18	—	18	32	—	32
Other	14	1	13	31	1	30
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$123	$98	$25	$337	$238	$99
Adjusted EBITDA related to unconsolidated affiliates:						
AmeriGas	$9	$4	$5	$122	$79	$43
Citrus	85	81	4	226	162	64
FEP	20	20	—	57	57	—
Regency	26	—	26	42	—	42
Other	11	1	10	27	4	23
Total Adjusted EBITDA related to unconsolidated affiliates	$151	$106	$45	$474	$302	$172
Distributions received from unconsolidated affiliates:						
AmeriGas	$19	$24	$(5)	$67	$70	$(3)
Citrus	47	38	9	110	63	47
FEP	18	18	—	51	53	(2)
Regency	14	—	14	29	—	29
Other	46	1	45	84	4	80
Total distributions received from unconsolidated affiliates	$144	$81	$63	$341	$190	$151

Segment Operating Results

Our reportable segments are discussed below. “All other” includes our compression operations, our equity method investment in AmeriGas, Southern Union’s local distribution operations, our approximate 30% non-operating interest in PES, our investment in Regency and our wholesale propane businesses.

Table of Contents

On January 12, 2012, we received an equity investment in AmeriGas as partial consideration for the contribution of our Propane Business to AmeriGas. As a result, our all other segment includes eleven days of consolidated activity related to our Propane Business for the nine months ended September 30, 2012. Amounts attributable to our investment in AmeriGas are reflected above in "Supplemental Information on Unconsolidated Affiliates."

We evaluate segment performance based on Segment Adjusted EBITDA, which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments. The tables below identify the components of Segment Adjusted EBITDA, which was calculated as follows:

- Gross margin, operating expenses, and selling, general and administrative. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- Unrealized gains or losses on commodity risk management activities. These are the unrealized amounts that are included in cost of products sold to calculate gross margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.
- Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- Adjusted EBITDA related to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for year ended December 31, 2012 filed with the SEC on March 1, 2013.

Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Natural gas transported (MMBtu/d)	9,438,372	9,942,575	(504,203)	9,608,792	9,995,218	(386,426)
Revenues	$553	$556	$(3)	$1,866	$1,532	$334
Cost of products sold	385	362	23	1,328	949	379
Gross margin	168	194	(26)	538	583	(45)
Unrealized (gains) losses on commodity risk management activities	(6)	(13)	7	(30)	54	(84)
Operating expenses, excluding non-cash compensation expense	(45)	(45)	—	(127)	(131)	4
Selling, general and administrative expenses, excluding non-cash compensation expense	(9)	(13)	4	(29)	(34)	5
Adjusted EBITDA related to unconsolidated affiliates	—	(2)	2	—	(2)	2
Segment Adjusted EBITDA	$108	$121	$(13)	$352	$470	$(118)

Volumes. Transported volumes decreased for the three and nine months ended September 30, 2013 due to the cessation of certain long-term contracts and lower volumes transported through our pipeline systems as a result of a continued unfavorable natural gas price environment.

Table of Contents

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Transportation fees	$121	$140	$(19)	$374	$421	$(47)
Natural gas sales and other	16	21	(5)	62	68	(6)
Retained fuel revenues	23	22	1	72	55	17
Storage margin, including fees	8	11	(3)	30	39	(9)
Total gross margin	$168	$194	$(26)	$538	$583	$(45)

Intrastate transportation and storage gross margin decreased for the three months ended September 30, 2013 compared to the same period last year due to the net impact of the following:

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

From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $5 million and $7 million during the three months ended September 30, 2013 and 2012, respectively.

- Natural gas sales and other. Margin from natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. Margin from natural gas sales and other decreased $5 million during the three months ended September 30, 2013 primarily due to gains during the comparable period last year from derivatives used to hedge retained fuel as natural gas prices declined.
- Retained fuel revenues. Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue for the three months ended September 30, 2013 reflected an increase of $2 million due to higher average of natural gas spot prices, partially offset by the impact of lower volumes of retention gas. The average spot price at the Houston Ship Channel for the three months ended September 30, 2013 increased to $3.54/MMBtu from $2.86/MMBtu in the same period last year.

Intrastate transportation and storage gross margin decreased for the nine months ended September 30, 2013 compared to the same period last year due to the net impact of the following:

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

Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $20 million and $27 million during the nine months ended September 30, 2013 and 2012, respectively.

- Natural gas sales and other. Margin from natural gas sales and other decreased $6 million in the nine months ended September 30, 2013 due to a decrease of $12 million from derivatives used to hedge retained fuel, partially offset by a gain of $6 million from gas sales and derivatives used to hedge transportation activities.
- Retained fuel revenues. Retention revenue for the nine months ended September 30, 2013 reflected an increase of $24 million due to higher average natural gas spot prices, partially offset by a reduction of $7 million due to lower volumes of retention gas. The average spot price at the Houston Ship Channel for the nine months ended September 30, 2013 increased to $3.65/MMBtu from $2.50/MMBtu in the same period last year.

Table of Contents

Storage margin was comprised of the following:

	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
Withdrawals from storage natural gas inventory (MMBtu)	—	5,258,344	(5,258,344)	36,962,300	9,698,738	27,263,562
Realized margin on natural gas inventory transactions	$(2)	$(3)	$1	$(16)	$76	$(92)
Fair value inventory adjustments	(2)	20	(22)	3	18	(15)
Unrealized gains (losses) on derivatives	5	(13)	18	22	(78)	100
Margin recognized on natural gas inventory, including related derivatives	1	4	(3)	9	16	(7)
Revenues from fee-based storage	7	7	—	21	23	(2)
Total storage margin	$8	$11	$(3)	$30	$39	$(9)

The decrease of $3 million in storage margin for the three months ended September 30, 2013 compared to the same period last year was due to a $22 million fair value adjustment to hedged storage gas, partially offset by gains of $18 million on derivatives used to hedge storage gas and $1 million gain on the sale of physical storage gas withdrawn. The decrease in storage margin for the nine months ended September 30, 2013 compared to the same period last year was primarily due to less physical withdrawals during the nine months ended September 30, 2012.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized gains and losses on commodity risk management activities reflect the net impact from storage and non-storage derivatives, as well as fair value adjustments to inventory. For the three months ended September 30, 2013, unrealized gains on derivatives of $9 million were offset by losses on the fair value adjustment to storage gas inventory of $2 million. For the three months ended September 30, 2012, unrealized gains on the fair value adjustment to storage gas inventory of $20 million were partially offset by unrealized losses on derivatives of $7 million. The unrealized gains on fair value adjustments to storage gas inventory for the three months ended September 30, 2012 reflected the impact of holding a larger volume of natural gas in our Bammel storage facility during an environment of increasing natural gas prices.

For the nine months ended September 30, 2013, unrealized gains of $30 million included unrealized gains on derivatives of $27 million and the fair value adjustment to storage gas inventory of $3 million. For the nine months ended September 30, 2012, unrealized losses on derivatives of $72 million were partially offset by gains on the fair value adjustment to storage gas inventory of $18 million. The unrealized losses on derivatives in the prior year were primarily related to storage natural gas, the impact from which was offset by realized derivative gains.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses for the three months ended September 30, 2013 compared to the same period last year reflected a $3 million decrease in ad valorem taxes, which was offset by other operating and maintenance expenses. Intrastate transportation and storage operating expenses for the nine months ended September 30, 2013 compared to the same period last year reflected a $4 million decrease in ad valorem taxes and a decrease of $3 million in operating and maintenance expenses, offset by an increase in fuel consumption.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses decreased for the three and nine months ended September 30, 2013 compared to the same periods last year primarily due to a decrease in employee-related costs, including allocated overhead expenses.

Table of Contents

Interstate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Natural gas transported (MMBtu/d)	6,081,246	6,637,914	(556,668)	6,436,455	6,596,756	(160,301)
Natural gas sold (MMBtu/d)	22,467	16,976	5,491	22,523	18,416	4,107
Revenues	$311	$321	$(10)	$992	$775	$217
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(83)	(58)	(25)	(224)	(170)	(54)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(23)	(40)	17	(83)	(123)	40
Adjusted EBITDA related to unconsolidated affiliates	105	101	4	283	219	64
Segment Adjusted EBITDA	$310	$324	$(14)	$968	$701	$267

Volumes. For the three and nine months ended September 30, 2013 compared to the same periods last year, transported volumes decreased on the Tiger pipeline due to declines in supply and transported volumes decreased on the Transwestern pipeline primarily due to a customer outage on the west end of the pipeline and lower basis differentials primarily on the eastern side of the pipeline. These decreases were partially offset by transportation volume increases for the three and nine months ended September 30, 2013 compared to the same period last year on the Panhandle Eastern and Trunkline Gas pipelines primarily due to higher basis differentials and increased volumes from the offshore consolidation on the Sea Robin pipeline.

Revenues. Interstate transportation and storage revenues decreased for the three months ended September 30, 2013 compared to the same period last year primarily due to overall lower capacity sold and lower rates, slightly offset by higher revenues from volumes transported on the Sea Robin and Trunkline Gas pipelines.

Interstate transportation and storage revenues increased for the nine months ended September 30, 2013 compared to the same period last year primarily due to the consolidation of Southern Union’s transportation and storage operations beginning March 26, 2012 and the recognition of $52 million received in connection with the buyout of a Southern Union customer’s contract. The increase was offset slightly by a decrease in revenues of $6 million related to the Transwestern and Tiger pipelines.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage operating expenses increased for the three months ended September 30, 2013 compared to the same period last year primarily due to an increase in operating and maintenance expenses of $8 million, higher fuel consumption costs of $6 million and increases in other operating expenses, including a $4 million unfavorable true-up adjustment to ad valorem taxes. For the nine months ended September 30, 2013 compared to the same period last year, operating expenses increased primarily due to the consolidation of Southern Union’s transportation and storage operations beginning March 26, 2012.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage selling, general and administrative expenses decreased for the three months ended September 30, 2013 compared to the same period last year primarily due to decreases in employee-related costs of $12 million and office expenses of $4 million as a result of cost reduction initiatives. For the nine months ended September 30, 2013 compared to the same period last year, interstate selling, general and administrative expenses decreased due to Southern Union’s recognition of merger-related expenses during the period from March 26, 2012 to March 31, 2012. This decrease was partially offset by the impact of consolidating Southern

Union's transportation and storage operations for only a partial period in 2012. With respect to the Transwestern and Tiger pipelines, selling, general and administrative expenses were approximately $2 million lower for the nine months ended September 30, 2013 compared to the same period last year.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased for the three and nine months ended September 30, 2013 compared to the same periods last year primarily due to Citrus. We acquired a 50% interest in Citrus on March 26, 2012; therefore, the 2012 period reflected only six months of Citrus.

Table of Contents

Midstream

	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
Gathered volumes (MMBtu/d):						
ETP legacy assets	2,745,362	2,463,987	281,375	2,698,562	2,327,284	371,278
Southern Union gathering and processing	—	434,452	(434,452)	492,586	415,910	76,676
NGLs produced (Bbls/d):						
ETP legacy assets	114,968	83,736	31,232	108,311	77,038	31,273
Southern Union gathering and processing	—	32,276	(32,276)	40,705	34,013	6,692
Equity NGLs produced (Bbls/d):						
ETP legacy assets	11,777	15,890	(4,113)	12,123	18,582	(6,459)
Southern Union gathering and processing	—	7,502	(7,502)	7,459	8,107	(648)
Revenues	$939	$864	$75	$2,796	$2,154	$642
Cost of products sold	777	682	95	2,309	1,674	635
Gross margin	162	182	(20)	487	480	7
Unrealized (gains) losses on commodity risk management activities	(1)	1	(2)	(5)	3	(8)
Operating expenses, excluding non-cash compensation expense	(29)	(37)	8	(117)	(105)	(12)
Selling, general and administrative expenses, excluding non-cash compensation expense	(7)	(16)	9	(43)	(57)	14
Adjusted EBITDA attributable to discontinued operations	—	5	(5)	—	15	(15)
Adjusted EBITDA related to unconsolidated affiliates	—	(1)	1	—	(1)	1
Segment Adjusted EBITDA	$125	$134	$(9)	$322	$335	$(13)

Volumes. Gathered volumes and NGL production for the ETP legacy assets increased during the three and nine months ended September 30, 2013 compared to the same period last year primarily due to increased production by our customers in the Eagle Ford Shale area. The decrease in equity NGL production for ETP's legacy assets was primarily due to processing plants optimizing NGL recoveries in response to the current NGL price environment. Volumes from Southern Union's gathering and processing operations were reflected through the deconsolidation on April 30, 2013.

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

	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
Gathering and processing fee-based revenues	$116	$89	$27	$327	$238	$89
Non fee-based contracts and processing	52	100	(48)	183	262	(79)
Other	(6)	(7)	1	(23)	(20)	(3)
Total gross margin	$162	$182	$(20)	$487	$480	$7

45

Table of Contents

Midstream gross margin decreased for the three months ended September 30, 2013 compared to the same period last year due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production in the Eagle Ford Shale resulted in increased fee-based revenues of $37 million. This increase was partially offset by a decrease of $3 million in fee-based revenues due to lower volumes on our Louisiana assets and a decrease of $6 million due to the deconsolidation of Southern Union’s gathering and processing operations on April 30, 2013.
- Non fee-based contracts and processing. Non fee-based gross margins decreased primarily due to the deconsolidation of Southern Union’s gathering and processing operations on April 30, 2013.

For the nine months ended September 30, 2013 compared to the same period last year, midstream gross margin increased between the periods due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production in the Eagle Ford Shale resulted in higher fee-based revenues of $93 million, which was partially offset by a decrease of $4 million from the deconsolidation of Southern Union’s gathering and processing operations on April 30, 2013.
- Non fee-based contracts and processing. Non fee-based gross margins decreased $25 million due to a decline in composite NGL prices. The composite NGL price for the nine months ended September 30, 2013 decreased to $0.91 per gallon from $1.23 per gallon in the same period last year. In addition, the deconsolidation of Southern Union’s gathering and processing operations on April 30, 2013 resulted in decreased non fee-based gross margins of $55 million.

Unrealized (Gains) Losses on Commodity Risk Management Activities. For the three and nine months ended September 30, 2013, our midstream segment recorded unrealized gains associated with our marketing and NGL hedging activities of $1 million and $5 million, respectively, compared to unrealized losses of $1 million and $3 million in the same periods last year primarily due to the timing of entering into hedges and the subsequent price changes.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the three months ended September 30, 2013 compared to the same period last year, operating expenses decreased due to the deconsolidation of Southern Union’s gathering and processing operations on April 30, 2013. This decrease was partially offset by an increase of $14 million in operating expenses on ETP’s legacy assets primarily due to additional expense from assets recently placed in service. For the nine months ended September 30, 2013 compared to the same period last year, the increase in operating expenses was primarily due to higher operating expenses on ETP’s legacy assets primarily due to additional expense from assets recently placed in service.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased for the three months ended September 30, 2013 compared to the same period last year primarily due to the contribution of Southern Union’s gathering and processing operations on April 30, 2013. For the nine months ended September 30, 2013 compared to the same period last year, midstream selling, general and administrative expenses decreased primarily due to Southern Union's recognition of merger-related expenses during the period from March 26, 2012 to March 31, 2012. This decrease was partially offset by the impact of consolidating Southern Union's gathering and processing operations for four months during the nine months ended September 30, 2013 compared to six months during the nine months ended September 30, 2012.

Table of Contents

NGL Transportation and Services

	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
NGL transportation volumes (Bbls/d)	340,483	174,234	166,249	319,269	166,825	152,444
NGL fractionation volumes (Bbls/d)	96,608	11,442	85,166	94,112	17,530	76,582
Revenues	$548	$168	$380	$1,351	$496	$855
Cost of products sold	426	101	325	1,012	285	727
Gross margin	122	67	55	339	211	128
Unrealized (gains) losses on commodity risk management activities	1	—	1	(1)	—	(1)
Operating expenses, excluding non-cash compensation expense	(19)	(13)	(6)	(66)	(43)	(23)
Selling, general and administrative expenses, excluding non-cash compensation expense	(6)	(5)	(1)	(19)	(15)	(4)
Adjusted EBITDA related to unconsolidated affiliates	2	1	1	4	2	2
Segment Adjusted EBITDA	$100	$50	$50	$257	$155	$102

Volumes. NGL transportation volumes increased for the three and nine months ended September 30, 2013 compared to the same period last year due to the completion of the Gateway and Justice pipelines in December 2012 and additional NGL production as a result of bringing our Jackson and Kenedy processing plants in service in February 2013 and December 2012, respectively. Average daily fractionated volumes increased for the three and nine months ended September 30, 2013 compared to the same period last year due to the commissioning of Lone Star’s fractionator at Mont Belvieu, Texas in December 2012. These volumes include all physical and contractual volumes where we collected a fractionation fee.

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

	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
Storage margin	$33	$35	$(2)	$99	$97	$2
Transportation margin	49	21	28	135	52	83
Processing and fractionation margin	38	12	26	102	63	39
Other margin	2	(1)	3	3	(1)	4
Total gross margin	$122	$67	$55	$339	$211	$128

NGL transportation and services gross margin increased for the three and nine months ended September 30, 2013 compared to the same period last year due to the following:

- Transportation margin. Transportation margin increased as a result of higher volumes transported out of West Texas due to the completion of the Gateway pipeline resulting in increased margin of $20 million and $59 million for the three and nine months ended September 30, 2013, respectively. The completion of our Justice pipeline connection to Mont Belvieu, Texas and additional NGL production from our processing plants accounted for the remainder of the increase in transportation margin for the three and nine months ended September 30, 2013.
- Processing and fractionation margin. Processing and fractionation margin increased due to the startup of Lone Star’s fractionator at Mont Belvieu, Texas in December 2012, which contributed an additional $21 million and $55 million

for three and nine months ended September 30, 2013, respectively. The increase in margin related to our fractionator was offset by a decrease in margin attributable to our fractionator in Geismar, Louisiana due to lower volumes and a less favorable pricing environment.

Table of Contents

Operating Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services operating expenses increased for the three and nine months ended September 30, 2013 compared to the same periods last year primarily due to increases of $6 million and $15 million, respectively, in operating expenses related to the start-up of Lone Star's fractionator. In addition, the nine months ended September 30, 2013 also reflected an increase of $6 million in ad valorem taxes as a result of assets placed in service in late 2012.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services selling, general and administrative expenses increased for the three and nine months ended September 30, 2013 compared to the same periods last year primarily due to an increase in employee-related costs, including allocated overhead expenses.

Investment in Sunoco Logistics

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Revenue	$4,528	$—	$4,528	$12,351	$—	$12,351
Cost of products sold	4,287	—	4,287	11,534	—	11,534
Gross margin	241	—	241	817	—	817
Unrealized gains on commodity risk management activities	(8)	—	(8)	(12)	—	(12)
Operating expenses, excluding non-cash compensation expense	(36)	—	(36)	(87)	—	(87)
Selling, general and administrative expenses, excluding non-cash compensation expense	(29)	—	(29)	(88)	—	(88)
Adjusted EBITDA related to unconsolidated affiliates	13	—	13	31	—	31
Segment Adjusted EBITDA	$181	$—	$181	$661	$—	$661

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

Table of Contents

Retail Marketing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Total retail gasoline outlets, end of period	4,972	—	4,972	4,972	—	4,972
Total company-operated outlets, end of period	443	—	443	443	—	443
Gasoline and diesel throughput per company-operated site (gallons/month)	202,500	—	202,500	215,920	—	215,920
Revenue	$5,298	$—	$5,298	$15,811	$—	$15,811
Cost of products sold	5,066	—	5,066	15,189	—	15,189
Gross margin	232	—	232	622	—	622
Unrealized losses on commodity risk management activities	1	—	1	1	—	1
Operating expenses, excluding non-cash compensation expense	(103)	—	(103)	(307)	—	(307)
Selling, general and administrative expenses, excluding non-cash compensation expense	(25)	—	(25)	(63)	—	(63)
LIFO valuation adjustments	(6)	—	(6)	(22)	—	(22)
Adjusted EBITDA related to unconsolidated affiliates	1	—	1	4	—	4
Other	—	—	—	(1)	—	(1)
Segment Adjusted EBITDA	$100	$—	$100	$234	$—	$234

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

All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Revenue	$95	$104	$(9)	$346	$319	$27
Cost of products sold	87	85	2	300	240	60
Gross margin	8	19	(11)	46	79	(33)
Unrealized losses on commodity risk management activities	5	1	4	2	3	(1)
Operating expenses, excluding non-cash compensation expense	(11)	(18)	7	(22)	(42)	20
Selling, general and administrative expenses, excluding non-cash compensation expense	(26)	3	(29)	(63)	(26)	(37)
Adjusted EBITDA attributable to discontinued operations	12	27	(15)	75	51	24
Adjusted EBITDA related to unconsolidated affiliates	31	3	28	156	79	77
Other	—	—	—	(11)	—	(11)

Elimination	(1)	(4)	3	(10)	(9)	(1)
Segment Adjusted EBITDA	$18	$31	$(13)	$173	$135	$38

Table of Contents

Amounts reflected in our all other segment primarily include:

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

The decrease in gross margin and operating expenses for the nine months ended September 30, 2013 compared to the same period last year was primarily due to the recognition of $31 million of gross margin and $18 million of operating expenses from our retail propane operations prior to the deconsolidation of those operations in January 2012.

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

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

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

Amounts reflected in "Other" above are primarily biodiesel tax credits recorded by Sunoco, which were included in gross margin but excluded from Segment Adjusted EBITDA.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

We currently expect capital expenditures for the full year 2013 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$5	$5	$25	$30
Interstate transportation and storage	40	50	75	90
Midstream[(1)]	455	475	40	45
NGL transportation and services[(2)]	420	425	15	20
Investment in Sunoco Logistics	880	920	60	65
Retail marketing	65	75	65	75
All other (including eliminations)	20	25	40	45
Total projected capital expenditures	$1,885	$1,975	$320	$370

(1) Amounts reflected above for the midstream segment include growth and maintenance capital expenditures of $95 million and $10 million, respectively, incurred by Southern Union's gathering and processing operations prior to deconsolidation on April 30, 2013.

(2) We expect to receive $120 million in capital contributions from Regency related to its 30% share of Lone Star.

Sunoco Logistics expects total growth capital expenditures of approximately $1.3 billion in 2014, and we expect to publicly announce expected 2014 capital expenditures for ETP's other segments prior to the filing of our Annual Report on Form 10-K for the year ended December 31, 2013.

Table of Contents

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, 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 our control. However, we include these factors in our anticipated growth capital expenditures for each year.

We generally fund our capital requirements with cash flows from operating activities, borrowings under the ETP Credit Facility, the issuance of long-term debt or Common Units or a combination thereof. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2013; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in “Results of Operations” above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense 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 we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Nine months ended September 30, 2013 compared to nine months ended September 30, 2012. Cash provided by operating activities during 2013 was $1.74 billion compared to $912 million for 2012 and net income was $1.24 billion and $1.29 billion for 2013 and 2012, respectively. The difference between net income and cash provided by operating activities for the nine months ended September 30, 2013 primarily consisted of net changes in operating assets and liabilities of $461 million and non-cash items totaling $751 million.

The non-cash activity in 2013 and 2012 consisted primarily of depreciation and amortization of $764 million and $419 million, respectively, and non-cash compensation expense of $36 million and $31 million, respectively.

Cash paid for interest, net of interest capitalized, was $725 million and $504 million for the nine months ended September 30, 2013 and 2012, respectively.

Capitalized interest for the nine months ended September 30, 2013 was $30 million.

Investing Activities

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

Nine months ended September 30, 2013 compared to nine months ended September 30, 2012. Cash used in investing activities during 2013 was $1.23 billion compared to $1.79 billion for 2012. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2013 were $1.84 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2012 of $1.94 billion. Additional detail related to our capital expenditures is provided in the table below. In 2013, we received $493 million, $973 million, and $346 million in cash from the SUGS Contribution, the sale of the MGE assets and the sale of AmeriGas common units, respectively, and paid net cash for acquisitions of $1.34 billion,

Table of Contents

primarily for the Holdco Acquisition. In addition, in 2012 we paid net cash for acquisitions of $1.42 billion, primarily for the Citrus Merger. We also received net cash proceeds of $1.44 billion from the contribution of the Propane Business in 2012.

The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the nine months ended September 30, 2013:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Intrastate transportation and storage	$1	$22	$23	$—	$23
Interstate transportation and storage	37	48	85	17	102
Midstream[(1)]	412	36	448	77	525
NGL transportation and services[(2)]	342	12	354	60	414
Investment in Sunoco Logistics	598	37	635	(30)	605
Retail marketing	41	47	88	10	98
All other (including eliminations)	12	32	44	18	62
Total	$1,443	$234	$1,677	$152	$1,829

(1) Amounts reflected above for the midstream segment include growth and maintenance capital expenditures of $95 million and $10 million, respectively, incurred by Southern Union's gathering and processing operations prior to deconsolidation on April 30, 2013.

(2) We received $100 million in capital contributions from Regency related to their 30% share of Lone Star.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.

Nine months ended September 30, 2013 compared to nine months ended September 30, 2012. Cash provided by financing activities during 2013 was $237 million compared to $885 million for 2012. In 2013, we received net proceeds from Common Unit offerings of $1.30 billion compared to $772 million in 2012. During 2013, we had a net increase in our debt level of $493 million compared to a net increase of $952 million for 2012. We incurred debt issuance costs of $30 million in 2013 compared to $20 million in 2012. We paid distributions of $1.34 billion to our partners in 2013 compared to $1.02 billion in 2012. We also paid distributions of $309 million to noncontrolling interests in 2013 compared to $39 million in 2012. In addition, we received capital contributions of $123 million from Regency for its noncontrolling interest in Lone Star compared to $240 million in 2012.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2013	December 31, 2012
ETP Debt	$11,148	$9,073
Transwestern Debt	869	869
Southern Union Debt	225	1,526
Panhandle Debt	1,028	1,757
Sunoco Debt	1,067	1,094
Sunoco Logistics Debt	2,309	1,732
Note Payable to ETE	—	166
Total	16,646	16,217
Less: current maturities	(294)	(609)
Long-term debt and notes payable, less current maturities	$16,352	$15,608

Table of Contents

The terms of our consolidated indebtedness are described in more detail in our Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on March 1, 2013 and in Note 7 to our consolidated financial statements.

September 2013 Senior Note Offering

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

Credit Facilities

ETP Credit Facility

ETP has a $2.5 billion revolving credit facility, the ETP Credit Facility, which expires in October 2016. Indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The ETP Credit Facility had no outstanding borrowings as of September 30, 2013.

Southern Union Credit Facility

Proceeds from the SUGS Contribution were used to repay $240 million of borrowings under the Southern Union Credit Facility and the facility was terminated.

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 and a $200 million unsecured credit facility which expires in August 2014. There were no outstanding borrowings under these facilities as of September 30, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility which expires in April 2015. Outstanding borrowings under this credit facility were $35 million as of September 30, 2013.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2013.

CASH DISTRIBUTIONS

Cash Distributions Paid by ETP

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

Following are distributions declared and/or paid by us subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 7, 2013	February 14, 2013	$0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375
June 30, 2013	August 5, 2013	August 14, 2013	0.89375
September 30, 2013	November 4, 2013	November 14, 2013	0.90500

Table of Contents

The total amounts of distributions declared during the nine months ended September 30, 2013 and 2012 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Nine Months Ended September 30, 2013	2012
Limited Partners:		
Common Units held by public	$740	$559
Common Units held by ETE	223	135
Class H Units held by ETE Holdings	16	—
General Partner interests held by ETE	15	15
IDRs held by ETE	528	381
IDR relinquishment related to previous acquisitions	(107)	(59)
Total distributions declared to the partners of ETP	$1,415	$1,031

The distributions reflected above for the nine months ended September 30, 2013 reflect IDR reductions totaling $107 million, which includes three quarters of IDR relinquishment related to the Citrus Merger, three quarters of IDR relinquishment related to the Holdco Transaction and two quarters of IDR relinquishment related to the Holdco Acquisition. The distributions reflected above for the nine months ended September 30, 2012 reflect IDR reductions totaling $59 million, which includes three quarters of IDR relinquishment related to the Citrus Merger and one quarter of IDR relinquishment related to the Holdco Transaction.

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

- In conjunction with the Partnership's Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.
- As discussed in Note 2, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.
- As discussed in Note 8 to our consolidated financial statements, ETP has agreed to make incremental cash distributions in the aggregate amount of $329 million to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017, in respect of the Class H units as a means to offset prior IDR subsidies that ETE agreed to in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition.

As a result, the net IDR subsidies from ETE, taking into account the incremental cash distributions related to the Class H units as an offset thereto, will be the amounts set forth in the table below:

	Quarters Ending March 31	June 30	September 30	December 31	Total Year
2013	N/A	N/A	$21.00	$21.00	$42.00
2014	$27.25	$27.25	27.25	27.25	109.00
2015	13.25	13.25	13.25	13.25	53.00
2016	5.50	5.50	5.50	5.50	22.00

Cash Distributions Paid by Sunoco Logistics

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

Table of Contents

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2012:

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

The total amounts of Sunoco Logistics distributions declared during the nine months ended September 30, 2013 were as follows (all from Available Cash from Sunoco Logistics' operating surplus and are shown in the period with respect to which they relate):

	Nine Months Ended September 30, 2013
Limited Partners	$186
General Partner interest	3
IDRs	84
Total distributions declared	$273

Sunoco Logistics declared $147 million in cash distributions to us for the nine months ended September 30, 2013.

CRITICAL ACCOUNTING POLICIES

Disclosure of our critical accounting policies is included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the SEC on March 1, 2013.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2012, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2012. Since December 31, 2012, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of September 30, 2013 and December 31, 2012, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Dollar amounts are presented in millions.

Table of Contents

	September 30, 2013			December 31, 2012		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives (Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	6,560,000	$(2)	$3	—	$—	$—
Basis Swaps IFERC/NYMEX [1]	(27,402,500)	(4)	1	(30,980,000)	(6)	—
Swing Swaps IFERC	1,690,000	—	1	—	—	—
Power (Megawatt):						
Forwards	562,250	1	2	19,650	—	1
Futures	97,212	—	1	(1,509,300)	(1)	1
Options — Calls	(1,700)	(2)	—	1,656,400	2	1
Crude (Bbls) — Futures	80,000	—	(1)	—	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(5,300,000)	(1)	—	150,000	(1)	—
Swing Swaps IFERC	6,965,000	(1)	2	(83,292,500)	1	1
Fixed Swaps/Futures	(14,072,500)	13	5	27,077,500	(7)	9
Forward Physical Contracts	(11,663,485)	1	—	11,689,855	—	2
Natural Gas Liquid (Bbls) — Forwards/Swaps	(1,182,000)	1	6	(30,000)	—	—
Refined Products (Bbls) — Futures	(93,327)	8	—	(666,000)	(3)	14
Fair Value Hedging Derivatives (Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(6,577,500)	—	—	(18,655,000)	(1)	—
Fixed Swaps/Futures	(47,215,000)	16	18	(44,272,500)	4	15
Cash Flow Hedging Derivatives (Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(1,150,000)	—	—	—	—	—
Fixed Swaps/Futures	(5,720,000)	—	2	(8,212,500)	(3)	3
Natural Gas Liquid (Bbls) — Forwards/Swaps	(720,000)	1	4	(930,000)	(2)	7
Refined Products (Bbls) — Futures	—	—	—	(98,000)	—	1
Crude (Bbls) — Futures	(120,000)	(2)	1	—	—	—

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

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

Interest Rate Risk

As of September 30, 2013, we had $641 million of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $6 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

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

Entity	Term	Type [(1)]	Notional Amount Outstanding September 30, 2013	Notional Amount Outstanding December 31, 2012
ETP	July 2013[(2)]	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$—	$400
ETP	July 2014[(2)]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.15% and receive a fixed rate of 4.65%	200	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	25	75
Southern Union	November 2021	Pay a fixed rate of 3.75% and receive a floating rate	450	450

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

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date. During the nine months ended September 30, 2013, we settled $400 million of ETP’s forward-starting interest rate swaps that had an effective date of July 2013.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $1 million as of September 30, 2013. For the $1.2 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $12 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled. For Southern Union’s interest rate swaps, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $5 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 exposure associated with a single or multiple counterparties.

Our counterparties consist of a diverse portfolio of customers across the energy industry including petrochemical companies, consumer and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure to credit risk may be affected either positively or negatively in that the counterparties may experience similar 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.

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.

57

Table of Contents

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of September 30, 2013 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Table of Contents

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2012 and Note 12 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2013.

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

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2012.

Table of Contents

ITEM 6. EXHIBITS

The exhibits listed below are filed as part of this report:

	Exhibit Number	Description
(*)	10.1	Exchange and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and ETE Common Holdings, LLC dated August 7, 2013.
	31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	101.INS	XBRL Instance Document
	101.SCH	XBRL Taxonomy Extension Schema Document
	101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
	101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
	101.LAB	XBRL Taxonomy Extension Label Linkbase Document
	101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Indicates exhibit incorporated by reference to Energy Transfer Partners, L.P. Current Report on Form 8-K filed on August 8, 2013.

** Furnished herewith.

Table of Contents

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	ENERGY TRANSFER PARTNERS, L.P.
	By: Energy Transfer Partners GP, L.P., its General Partner
	By: Energy Transfer Partners, L.L.C., its General Partner
Date: November 7, 2013	By: /s/ Martin Salinas, Jr. Martin Salinas, Jr. Chief Financial Officer (duly authorized to sign on behalf of the registrant)