Energy Transfer Partners, L.P.
Form 10-Q
August 08, 2013
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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 June 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 August 2, 2013, the registrant had units outstanding as follows:
Energy Transfer Partners, L.P. 376,218,425 Common Units

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (“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 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
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
MMBtu	million British thermal units
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OTC	over-the-counter
OSHA	federal Occupational Safety and Health Act
Panhandle	Panhandle Eastern Pipe Line Company, LP
PCBs	polychlorinated biphenyls
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC
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.

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

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$532	$311
Accounts receivable, net	3,079	2,910
Accounts receivable from related companies	172	94
Inventories	1,603	1,495
Exchanges receivable	36	55
Price risk management assets	44	21
Current assets held for sale	102	184
Other current assets	290	334
Total current assets	5,858	5,404
PROPERTY, PLANT AND EQUIPMENT	26,766	27,412
ACCUMULATED DEPRECIATION	(2,032)	(1,639)
	24,734	25,773
NON-CURRENT ASSETS HELD FOR SALE	1,000	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,884	3,502
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	20	42
GOODWILL	5,206	5,606
INTANGIBLE ASSETS, net	1,508	1,561
OTHER NON-CURRENT ASSETS, net	441	357
Total assets	$43,651	$43,230

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

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

	June 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,199	$3,002
Accounts payable to related companies	34	24
Exchanges payable	151	156
Price risk management liabilities	51	110
Accrued and other current liabilities	1,323	1,562
Current maturities of long-term debt	895	609
Current liabilities held for sale	75	85
Total current liabilities	5,728	5,548
NON-CURRENT LIABILITIES HELD FOR SALE	140	142
LONG-TERM DEBT, less current maturities	16,243	15,442
LONG-TERM NOTES PAYABLE — RELATED PARTY	—	166
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	88	129
DEFERRED INCOME TAXES	3,767	3,476
OTHER NON-CURRENT LIABILITIES	902	995
COMMITMENTS AND CONTINGENCIES (Note 12)		
EQUITY:		
General Partner	195	188
Limited Partners:		
Common Unitholders	11,912	9,026
Accumulated other comprehensive loss	(9)	(13)
Total partners' capital	12,098	9,201
Noncontrolling interest	4,685	8,131
Total equity	16,783	17,332
Total liabilities and equity	$43,651	$43,230

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
REVENUES:				
Natural gas sales	$691	$494	$1,565	$917
NGL sales	588	471	1,177	840
Crude sales	3,992	—	7,193	—
Gathering, transportation and other fees	692	506	1,329	899
Refined product sales	4,650	—	9,312	—
Other	938	125	1,829	263
Total revenues	11,551	1,596	22,405	2,919
COSTS AND EXPENSES:				
Cost of products sold	10,229	799	19,823	1,580
Operating expenses	315	196	619	326
Depreciation and amortization	251	158	511	257
Selling, general and administrative	124	86	286	190
Total costs and expenses	10,919	1,239	21,239	2,353
OPERATING INCOME	632	357	1,166	566
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(211)	(191)	(422)	(332)
Equity in earnings of unconsolidated affiliates	37	1	109	56
Gain on deconsolidation of Propane Business	—	1	—	1,057
Loss on extinguishment of debt	—	—	—	(115)
Gains (losses) on interest rate derivatives	39	(37)	46	(9)
Other, net	(4)	4	(1)	3
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	493	135	898	1,226
Income tax expense from continuing operations	89	7	92	9
INCOME FROM CONTINUING OPERATIONS	404	128	806	1,217
Income from discontinued operations	9	7	31	6
NET INCOME	413	135	837	1,223
LESS: NET INCOME (LOSS) ATTRIBUTABLE TO NONCONTROLLING INTEREST	93	24	195	(3)
NET INCOME ATTRIBUTABLE TO PARTNERS	320	111	642	1,226
GENERAL PARTNER’S INTEREST IN NET INCOME	155	109	283	226
LIMITED PARTNERS’ INTEREST IN NET INCOME	$165	$2	$359	$1,000
INCOME (LOSS) FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:				
Basic	$0.52	$(0.03)	$1.04	$4.32
Diluted	$0.52	$(0.03)	$1.04	$4.30
NET INCOME PER LIMITED PARTNER UNIT:				
Basic	$0.53	$0.00	$1.08	$4.35
Diluted	$0.53	$0.00	$1.08	$4.33

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$413	$135	$837	$1,223
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(1)	(9)	(2)	(12)
Change in value of derivative instruments accounted for as cash flow hedges	6	1	8	21
Change in value of available-for-sale securities	(1)	—	—	—
Actuarial gain relating to pension and other postretirement benefits	2	—	1	—
Foreign currency translation adjustment	—	—	(1)	—
Change in other comprehensive income from equity investments	(3)	(22)	4	(22)
	3	(30)	10	(13)
Comprehensive income	416	105	847	1,210
Less: Comprehensive income attributable to noncontrolling interest	91	13	192	24
Comprehensive income attributable to partners	$325	$92	$655	$1,186

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

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

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance, December 31, 2012	$188	$9,026	$(13)	$8,131	$17,332
Distributions to partners	(276)	(597)	—	—	(873)
Distributions to noncontrolling interest	—	—	—	(247)	(247)
Units issued for cash	—	1,090	—	—	1,090
Capital contributions from noncontrolling interest	—	—	—	49	49
Holdco Acquisition and SUGS Contribution (See Note 2)	—	2,020	(5)	(3,445)	(1,430)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	18	—	6	24
Other comprehensive income (loss), net of tax	—	—	13	(3)	10
Other, net	—	(4)	(4)	(1)	(9)
Net income	283	359	—	195	837
Balance, June 30, 2013	$195	$11,912	$(9)	$4,685	$16,783

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

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

	Six Months Ended June 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$837	$1,223
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	511	257
Deferred income taxes	73	6
Gain on curtailment of other postretirement benefits	—	(15)
Amortization of finance costs charged to interest	(47)	(3)
Loss on extinguishment of debt	—	115
LIFO valuation adjustment	(16)	—
Non-cash compensation expense	24	21
Gain on deconsolidation of Propane Business	—	(1,057)
Distributions on unvested awards	(6)	(4)
Equity in earnings of unconsolidated affiliates	(109)	(56)
Distributions from unconsolidated affiliates	154	56
Other non-cash	20	33
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 3)	(277)	(107)
Net cash provided by operating activities	1,164	469
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 (paid) received from all other acquisitions	(5)	471
Capital expenditures (excluding allowance for equity funds used during construction)	(1,131)	(1,096)
Contributions in aid of construction costs	11	12
Contributions to unconsolidated affiliates	(1)	(2)
Distributions from unconsolidated affiliates in excess of cumulative earnings	43	53
Proceeds from the sale of assets	19	13
Other	(25)	(2)
Net cash used in investing activities	(1,928)	(1,003)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	3,960	3,533
Repayments of long-term debt	(2,832)	(2,487)
Repayments of borrowings from affiliates	(166)	—
Net proceeds from issuance of Limited Partner units	1,090	94
Capital contributions received from noncontrolling interest	72	151
Distributions to partners	(873)	(628)
Distributions to noncontrolling interest	(247)	(18)
Debt issuance costs	(19)	(20)
Net cash provided by financing activities	985	625
INCREASE IN CASH AND CASH EQUIVALENTS	221	91
CASH AND CASH EQUIVALENTS, beginning of period	311	107

CASH AND CASH EQUIVALENTS, end of period	$532	$198

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)
(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 interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS.
- 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;
- interstate natural gas transportation and storage;

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•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 June 30, 2013 and for the three and six month periods ended June 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 June 30, 2013, and the Partnership’s results of operations and cash flows for the three and six months ended June 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 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 definitive purchase and sale agreements dated December 14, 2012 (collectively, the “Purchase and Sale Agreements”) with each of Plaza Missouri Acquisition, Inc. (“Laclede Missouri”) and Plaza Massachusetts Acquisition, Inc. (“Laclede Massachusetts”), both of which are subsidiaries of The Laclede Group, Inc., pursuant to which Laclede Missouri has agreed to acquire the assets of Southern Union’s Missouri Gas Energy division, and Laclede Massachusetts has agreed to acquire the assets of Southern Union’s New England Gas Company division. Total consideration for the acquisitions will be $1.04 billion, subject to customary closing adjustments, less the assumption of $19 million of debt. In February 2013, the Laclede Entities entered into an agreement with Algonquin Power & Utilities Corp (“APUC”) that will allow a subsidiary of APUC to assume the right of the Laclede Entities to purchase the assets of Southern Union’s New England Gas Company division, subject to certain approvals. The sale of Southern Union’s Missouri Gas Energy division is expected to close on or after September 1, 2013. The sale of Southern Union’s New England Gas Company division is expected to close in the fourth quarter of 2013.

For the three and six months ended June 30, 2013 and the period from March 26, 2012 to June 30, 2012, the distribution operations have been classified as discontinued operations in the consolidated statements of operations. The assets and liabilities of the disposal group have been classified as assets and liabilities held for sale as of June 30, 2013 and December 31, 2012.

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of

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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. Management is continuing to validate certain assumptions made in connection with the purchase price allocation of Sunoco; therefore, certain assets and/or liabilities may be adjusted.

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:

	Six Months Ended June 30,	
	2013	2012
Accounts receivable	$(206)	$43
Accounts receivable from related companies	(63)	(33)
Inventories	(64)	(50)
Exchanges receivable	(5)	8
Other current assets	72	86
Other non-current assets, net	(32)	22
Accounts payable	177	(39)
Accounts payable to related companies	(65)	79
Exchanges payable	(2)	(3)
Accrued and other current liabilities	48	(232)
Other non-current liabilities	(34)	(7)
Price risk management assets and liabilities, net	(103)	19
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$(277)	$(107)

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Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2013	2012
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$405	$434
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	$—	$24
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:

	June 30, 2013	December 31, 2012
Natural gas and NGLs	$354	$334
Crude oil	548	418
Refined products	531	572
Appliances, parts and fittings and other	170	171
Total inventories	$1,603	$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 marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider 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 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 six months ended June 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 June 30, 2013 and December 31, 2012 was $17.78 billion and $17.84 billion, respectively. As of June 30, 2013 and December 31, 2012, the aggregate carrying amount of our consolidated debt obligations was $17.14 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.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2013 and December 31, 2012 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2013	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$39	$—	$39
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	5	5	—
Swing Swaps IFERC	3	—	3
Fixed Swaps/Futures	69	68	1
Options — Puts	1	—	1
Options — Calls	1	—	1
Forward Physical Swaps	1	—	1
Power:			
Forwards	9	—	9
Futures	2	2	—
Options — Calls	8	—	8
Natural Gas Liquids — Forwards/Swaps	16	16	—
Total commodity derivatives	115	91	24
Total Assets	$154	$91	$63
Liabilities:			
Interest rate derivatives	$(117)	$—	$(117)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(9)	(9)	—
Swing Swaps IFERC	(4)	—	(4)
Fixed Swaps/Futures	(59)	(54)	(5)
Options — Puts	(1)	—	(1)
Options — Calls	(1)	—	(1)
Power:			
Forwards	(9)	—	(9)
Futures	(2)	(2)	—
Options — Calls	(5)	—	(5)
Natural Gas Liquids — Forwards/Swaps	(6)	(6)	—
Crude — Futures	(1)	(1)	—
Total commodity derivatives	(97)	(72)	(25)
Total Liabilities	$(214)	$(72)	$(142)

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	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.

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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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Income from continuing operations	$404	$128	$806	$1,217
Less: Income (loss) from continuing operations attributable to noncontrolling interest	89	24	178	(3)
Income from continuing operations, net of noncontrolling interest	315	104	628	1,220
General Partner's interest in income from continuing operations	154	108	282	225
Limited Partners' interest in income (loss) from continuing operations	161	(4)	346	995
Additional earnings allocated from General Partner	23	—	—	—
Distributions on employee unit awards, net of allocation to General Partner	(2)	(2)	(5)	(9)
Income (loss) from continuing operations available to Limited Partners	$182	$(6)	$341	$986
Weighted average Limited Partner units – basic	352.6	229.7	326.9	228.1
Basic income (loss) from continuing operations per Limited Partner unit	$0.52	$(0.03)	$1.04	$4.32
Dilutive effect of unvested Unit Awards	1.2	—	1.2	1.0
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	353.8	229.7	328.1	229.1
Diluted income (loss) from continuing operations per Limited Partner unit	$0.52	$(0.03)	$1.04	$4.30
Basic income from discontinued operations per Limited Partner unit	$0.01	$0.03	$0.04	$0.03
Diluted income from discontinued operations per Limited Partner unit	$0.01	$0.03	$0.04	$0.03

7. DEBT OBLIGATIONS:

Senior Notes

In January 2013, ETP issued $800 million of 3.6% Senior Notes due February 2023 and $450 million 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 of 3.45% Senior Notes due January 2023 and $350 million 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.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion total 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.

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Credit Facilities
ETP Credit Facility
ETP has a $2.5 billion revolving credit facility (the "ETP Credit Facility") that 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.
As of June 30, 2013, the ETP Credit Facility had $900 million outstanding, and the amount available for future borrowings was $1.49 billion after taking into account letters of credit of $107 million. The weighted average interest rate on the total amount outstanding as of June 30, 2013 was 1.70%.
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 2013. There were no outstanding borrowings under these credit facilities as of June 30, 2013.
West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility. Outstanding borrowings under this credit facility were $35 million as of June 30, 2013.
Compliance with Our Covenants
We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of June 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
On August 7, 2013, ETP, ETE and ETE Common Holdings, LLC, a wholly owned subsidiary of ETE ("ETE Holdings") entered into an Exchange and Redemption Agreement, pursuant to which ETP has agreed to redeem and cancel 50.2 million of its common units representing limited partner interests (the "Redeemed Units") currently owned by ETE Holdings 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 will generally be entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50% 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% 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 ending 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.

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This transaction is subject to certain customary closing conditions. In the Exchange and Redemption Agreement, ETP, ETE and ETE Holdings have made customary representations and warranties and have agreed to customary covenants relating to this transaction.

Common Units Issued

The change in Common Units during the six months ended June 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	8.0
Common Units issued in connection with the Distribution Reinvestment Plan	1.0
Common Units issued in connection with certain acquisitions	49.5
Outstanding at June 30, 2013	373.8

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 six months ended June 30, 2013, we received proceeds of $387 million, net of commissions of $4 million, from the issuance of units pursuant to the Equity Distribution Agreements, which proceeds were used for general partnership purposes. We also received $26 million net of commissions, in July 2013 from the settlement of transactions initiated in June 2013 under these agreements. Approximately $609 million of our Common Units remain available to be issued under these agreements.

During the six months ended June 30, 2013, distributions of $46 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 1.0 million Common Units. As of June 30, 2013, a total of 3.3 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.

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

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 of $329 million, subject over 15 quarters, commencing with the quarter ending 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.

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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

Accumulated Other Comprehensive Loss

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

	June 30, 2013	December 31, 2012
Net gains on commodity related hedges	$6	$—
Foreign currency translation adjustment	(1)	—
Actuarial loss related to pensions and other postretirement benefits	(9)	(10)
Equity investments, net	(5)	(9)
Subtotal	(9)	(19)
Amounts attributable to noncontrolling interest	—	6
Total accumulated other comprehensive loss, net of tax	$(9)	$(13)

9. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plans

During the six months ended June 30, 2013, employees were granted a total of 1,074,163 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 $45.37 per unit. As of June 30, 2013 a total of 2,827,915 unit awards remain unvested, for which we expect to recognize $76 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 June 30, 2013, a total of 936,438 Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $19 million in compensation expense over a weighted-average period of 2.5 years.

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10. INCOME TAXES:

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Income tax expense from continuing operations	$89	$7	$92	$9
Effective tax rate	18 %	5 %	10 %	1 %

The increase in the effective tax rate for the three and six months ended June 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 October 2012.

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 June 30,			
	2013		2012[1]	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$3	$1	$2	$—
Interest cost	9	1	(1)	1
Expected return on plan assets	(15)	(1)	(1)	(2)
	(3)	1	—	(1)
Regulatory adjustment[3]	2	(3)	—	1
Net periodic benefit cost	$(1)	$(2)	$—	$—

	Six Months Ended June 30,			
	2013		2012[1]	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$5	$1	$2	$—
Interest cost	18	3	(1)	1
Expected return on plan assets	(30)	(4)	(1)	(2)
Actuarial loss amortization	1	—	—	—
Settlement credits	(2)	—	—	—
Curtailment recognition[2]	—	—	—	(15)
	(8)	—	—	(16)
Regulatory adjustment[3]	4	—	—	1
Net periodic benefit cost	$(4)	$—	$—	$(15)

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

(2) 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

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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.

(3) In its distribution operations, Southern Union recovers certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

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

FERC Audit

The FERC is currently conducting 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. A draft audit report was received on July 19, 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 $30 million and $11 million for the three months ended June 30, 2013 and 2012, respectively, which include contingent rentals totaling $6 million in the three months ended June 30, 2013. For the six months ended June 30, 2013 and 2012, rental expense for operating leases totaled $62 million and $17 million, respectively, which include contingent rentals totaling $10 million in the six months ended June 30, 2013. During the three and six months ended June 30, 2013, $5 million and $10 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

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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.

The Texas case remains pending, and discovery is ongoing.

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 June 30, 2013, Sunoco was a defendant in two lawsuits involving one state and Puerto Rico. These cases are venued in a multidistrict proceeding in a New York federal court. Both cases assert natural resource damage claims. In addition, Sunoco has received notice from another state that it intends to file an MTBE lawsuit in the near future asserting natural resource damage claims.

Discovery is proceeding in these cases. There has been insufficient information developed about the plaintiffs' legal theories or the facts in the natural resource damage claims that would be relevant to an analysis of the ultimate liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that 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. The parties are drafting a stipulation of settlement (with proposed judgment) and will have a settlement hearing likely in August 2013 for the Court to approve the settlement, which will dispose of the case. It is unlikely the Court will reject the settlement.

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 June 30, 2013 and December 31, 2012, accruals of approximately $36 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 June 30, 2013 or December 31, 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Will Price. Will Price, an individual, filed actions in the U.S. District Court for the District of Kansas for damages against a number of companies, including Panhandle, alleging mis-measurement of natural gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On September 19, 2009, the Court denied plaintiffs' request for class certification. Plaintiffs have filed a motion for reconsideration, which the Court denied on March 31, 2010. Panhandle believes that its measurement practices conformed to the terms of its FERC natural gas tariffs, which were filed with and approved by the FERC. As a result, Southern Union believes that it has meritorious defenses to the Will Price lawsuit (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Panhandle complied with the terms of its tariffs). Panhandle will continue to vigorously defend the case. Southern Union believes it has no liability associated with this proceeding.

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. One person died and media reports indicate that up to fifteen people were transported to area hospitals. The extent and nature of those injuries are currently unknown. The restaurant building was destroyed in the explosion and fire. Immediately surrounding buildings sustained damage, but the full extent of that damage is unknown at this time. A contractor, Heartland Midwest LLC, was in the process of installing cable for Time Warner Cable and hit a natural gas line while directionally boring. The utility locates for the work were done by USIC Locating

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Services, Inc., a utility infrastructure locating company engaged by Missouri Gas Energy to locate and mark underground gas lines (and engaged by others to mark other underground facilities). Several parties have retained counsel, and to date, nine lawsuits have been filed in the Circuit Court of Jackson County, Missouri, against numerous defendants. MGE and MGE employee, Michael Palier, are defendants in all but one of the lawsuits (Palier v. Time Warner). The lawsuits filed to date include Simmons v. MGE, Case No. 1316-CV07265 (no trial date set); Tanner v. MGE, Case No. 1316-CV09906 (no trial date set), JJ's Restaurant v. MGE, Case No. 1316-CV11288 (two trial dates set on January 12, 2015 and April 6, 2015); Meek v. MGE, Case No. 1316-CV13523 (no trial date set); Cramer v. MGE, Case No. 1316-CV13738 (no trial date set); Plazaview, LLC v. MGE, Case No. 1316-CV16817 (no trial date set); Mingos v. MGE, Case No. 1316-CV18072 (no trial date set); Palier v. Time Warner, Case No. 1316-CV18684 (no trial date set); and Couture v. MGE, Case No. 1316-CV18787 (no trial date set). Discovery in the pending lawsuits is ongoing. No demands have been made in any of the pending lawsuits. The Partnership anticipates that more lawsuits will be filed. The Missouri Public Service Commission and the Occupational Safety and Health Administration investigations are ongoing. The Partnership will assess its potential exposure as the matter progresses as no estimate can be made at this time.

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. Moreover, there can be no assurance that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the

operations, will not result in substantial costs and liabilities. We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.
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.

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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 local 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 June 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.

	June 30, 2013	December 31, 2012
Current	$38	$46
Non-current	150	165
Total environmental liabilities	$188	$211

During the three and six months ended June 30, 2013, Sunoco recorded $8 million and $15 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 is required by October 2013.

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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 the 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 the our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

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.

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The following table details our outstanding commodity-related derivatives:

	June 30, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	9,650,000	2013-2015	—	—
Basis Swaps IFERC/NYMEX [1]	(37,702,500)	2013-2014	(30,980,000)	2013-2014
Power (Megawatt):				
Forwards	145,078	2013	19,650	2013
Futures	(557,260)	2013	(1,509,300)	2013
Options — Calls	(1,200)	2013	1,656,400	2013
Crude (Bbls) — Futures	(80,000)	2013	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	8,770,000	2013-2014	150,000	2013
Swing Swaps IFERC	20,060,000	2013	(83,292,500)	2013
Fixed Swaps/Futures	23,435,000	2013-2015	27,077,500	2013
Forward Physical Contracts	1,758,402	2013-2014	11,689,855	2013-2014
Natural Gas Liquid (Bbls):				
Forwards/Swaps	(597,000)	2013-2014	(30,000)	2013
Refined Products (Bbls) — Futures	(1,227,000)	2013	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(10,530,000)	2013	(18,655,000)	2013
Fixed Swaps/Futures	(32,682,500)	2013	(44,272,500)	2013
Hedged Item — Inventory	32,682,500	2013	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(2,300,000)	2013	—	—
Fixed Swaps/Futures	(4,140,000)	2013	(8,212,500)	2013
Natural Gas Liquid (Bbls):				
Forwards/Swaps	(690,000)	2013	(930,000)	2013
Refined Products (Bbls) — Futures	—	—	(98,000)	2013
Crude (Bbls) — Futures	(210,000)	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 $6 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

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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	
			June 30, 2013	December 31, 2012
ETP	July 2013[2]	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$100	$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	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 2.91% and receive a floating rate	75	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.

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. The Partnership had net deposits with counterparties of $34 million and $41 million as of June 30, 2013 and December 31, 2012, respectively.

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

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Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2013	December 31, 2012	June 30, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$20	$8	$(2)	$(10)
	20	8	(2)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	81	110	(80)	(116)
Commodity derivatives	78	33	(75)	(34)
Current assets held for sale	1	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	(5)	(9)
Interest rate derivatives	39	55	(117)	(223)
	199	200	(277)	(382)
Total derivatives	$219	$208	$(279)	$(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	
Contract Type	Balance Sheet Location	June 30, 2013	December 31, 2012	June 30, 2013	December 31, 2012
OTC contracts	Price risk management asset (liability)	$82	$28	$(81)	$(27)
Broker cleared derivative contracts	Other current assets (liabilities)	171	150	(155)	(228)
	Gross fair value	253	178	(236)	(255)
Collateral paid to OTC counterparties	Other current assets (liabilities)	—	—	—	2
Counterparty netting	Price risk management asset (liability)	(63)	(25)	63	25
Payments on margin deposit	Other current assets (liabilities)	(11)	—	16	59
	Net fair value	179	153	(157)	(169)
	Other derivatives – gross	40	55	(122)	(223)
	Total derivatives	$219	$208	$(279)	$(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.

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$6	$1	$8	$21
Total	$6	$1	$8	$21

	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 June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$1	$9	$2	$12
Total		$1	$9	$2	$12

	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 June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$(1)	$34	$4	$25
Total		$(1)	$34	$4	$25

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$3	$—	$(1)	$(11)
Commodity derivatives – Non-Trading	Cost of products sold	21	(5)	3	(8)
Commodity derivatives – Non-Trading	Deferred gas purchases	2	—	(3)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	39	(37)	46	(9)
Total		$65	$(42)	$45	$(28)

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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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Affiliated revenue	$333	$10	$715	$17

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

	June 30, 2013	December 31, 2012
Accounts receivable from related companies:		
ETE	$31	$16
Regency	50	10
PES	43	60
FGT	33	2
Other	15	6
Total accounts receivable from related companies:	$172	$94
Accounts payable to related companies:		
ETE	$8	$7
Regency	14	2
PES	7	13
FGT	3	—
Other	2	2
Total accounts payable to related companies:	$34	$24

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15. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	June 30, 2013	December 31, 2012
Deposits paid to vendors	$34	$41
Prepaid expenses and other	256	293
Total other current assets	$290	$334

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2013	December 31, 2012
Interest payable	$263	$256
Customer advances and deposits	83	44
Accrued capital expenditures	319	356
Accrued wages and benefits	107	236
Taxes payable other than income taxes	260	203
Income taxes payable	37	40
Deferred income taxes	84	130
Deferred revenue	3	—
Other	167	297
Total accrued and other current liabilities	$1,323	$1,562

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 of America, 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

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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.

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The following tables present the financial information by segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$558	$452	$1,209	$899
Intersegment revenues	65	42	104	77
	623	494	1,313	976
Interstate transportation and storage:				
Revenues from external customers	354	310	677	452
Intersegment revenues	3	2	4	2
	357	312	681	454
Midstream:				
Revenues from external customers	588	629	1,338	1,088
Intersegment revenues	318	98	519	202
	906	727	1,857	1,290
NGL transportation and services:				
Revenues from external customers	420	148	766	302
Intersegment revenues	18	13	37	26
	438	161	803	328
Investment in Sunoco Logistics:				
Revenues from external customers	4,256	—	7,713	—
Intersegment revenues	55	—	110	—
	4,311	—	7,823	—
Retail marketing:				
Revenues from external customers	5,291	—	10,508	—
Intersegment revenues	—	—	5	—
	5,291	—	10,513	—
All other:				
Revenues from external customers	84	57	194	178
Intersegment revenues	17	29	57	37
	101	86	251	215
Eliminations	(476)	(184)	(836)	(344)
Total revenues	$11,551	$1,596	$22,405	$2,919

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$112	$157	$244	$349
Interstate transportation and storage	361	297	658	377
Midstream	118	102	197	191
NGL transportation and services	77	55	157	105
Investment in Sunoco Logistics	244	—	480	—
Retail marketing	97	—	134	—
All other	60	31	155	114
Total	1,069	642	2,025	1,136
Depreciation and amortization	(251)	(158)	(511)	(257)
Interest expense, net of interest capitalized	(211)	(191)	(422)	(332)
Gain on deconsolidation of Propane Business	—	1	—	1,057
Gains (losses) on interest rate derivatives	39	(37)	46	(9)
Non-cash unit-based compensation expense	(10)	(10)	(24)	(21)
Unrealized gains (losses) on commodity risk management activities	18	15	37	(71)
LIFO valuation adjustment	(22)	—	16	—
Loss on extinguishment of debt	—	—	—	(115)
Adjusted EBITDA attributable to discontinued operations	(23)	(27)	(63)	(34)
Adjusted EBITDA related to unconsolidated affiliates	(158)	(97)	(323)	(196)
Equity in earnings of unconsolidated affiliates	37	1	109	56
Other, net	5	(4)	8	12
Income from continuing operations before income tax expense	$493	$135	$898	$1,226

	June 30, 2013	December 31, 2012
Total assets:		
Intrastate transportation and storage	$4,609	$4,691
Interstate transportation and storage	11,834	11,794
Midstream	3,038	5,098
NGL transportation and services	3,960	3,765
Investment in Sunoco Logistics	10,977	10,291
Retail marketing	3,780	3,926
All other	5,453	3,665
Total	$43,651	$43,230

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

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

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. In addition, PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. Upon the closing of the transaction, ETE agreed to forego incentive distributions with respect to the Regency common units issued in the transaction for the first eight consecutive quarters following the closing.

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. 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. As a result, ETP now owns 100% of Holdco.

Equity Offering

In April 2013, the Partnership issued 13.8 million Common Units at $48.05 per Common Unit in a 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.

Note Exchange

On June 24, 2013, the Partnership completed the exchange of approximately $1.09 billion total 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 the Partnership with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Sale of AmeriGas Common Units

On July 12, 2013, 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.

Class H Units

On August 7, 2013, ETP, ETE and ETE Holdings entered into an Exchange and Redemption Agreement, pursuant to which ETP has agreed to redeem and cancel 50.2 million of its common units representing limited partner interests currently owned by ETE Holdings in exchange for the issuance by ETP to ETE Holdings of the new Class H Units of limited partner interest in ETP which will generally be entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50% 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% 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 ending 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.

This transaction is subject to certain customary closing conditions. In the Exchange and Redemption Agreement, ETP, ETE and ETE Holdings have made customary representations and warranties and have agreed to customary covenants relating to this transaction.

In connection with this transaction, ETP has agreed to make incremental cash distributions of $329 million over 15 quarters, commencing with the quarter ending 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 to ETP taking into account the incremental cash distributions related to the Class H Units as an offset thereto will be $21 million with respect to each of the quarters ending September 30, 2013 and 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 plc 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 2.0 Bcf/d of natural gas in the form 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,

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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.

Results of Operations

Consolidated Results

	Three Months Ended June 30, 2013	2012	Change	Six Months Ended June 30, 2013	2012	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$112	$157	$(45)	$244	$349	$(105)
Interstate transportation and storage	361	297	64	$658	377	281
Midstream	118	102	16	197	191	6
NGL transportation and services	77	55	22	157	105	52
Investment in Sunoco Logistics	244	—	244	480	—	480
Retail marketing	97	—	97	134	—	134
All other	60	31	29	155	114	41
Total	1,069	642	427	2,025	1,136	889
Depreciation and amortization	(251)	(158)	(93)	(511)	(257)	(254)
Interest expense, net of interest capitalized	(211)	(191)	(20)	(422)	(332)	(90)
Gain on deconsolidation of Propane Business	—	1	(1)	—	1,057	(1,057)
Gains (losses) on interest rate derivatives	39	(37)	76	46	(9)	55
Non-cash unit-based compensation expense	(10)	(10)	—	(24)	(21)	(3)
Unrealized gains (losses) on commodity risk management activities	18	15	3	37	(71)	108
LIFO valuation adjustment	(22)	—	(22)	16	—	16
Loss on extinguishment of debt	—	—	—	—	(115)	115
Adjusted EBITDA attributable to discontinued operations	(23)	(27)	4	(63)	(34)	(29)
Adjusted EBITDA related to unconsolidated affiliates	(158)	(97)	(61)	(323)	(196)	(127)
Equity in earnings of unconsolidated affiliates	37	1	36	109	56	53
Other, net	5	(4)	9	8	12	(4)
Income from continuing operations before income tax expense	493	135	358	898	1,226	(328)
Income tax expense from continuing operations	(89)	(7)	(82)	(92)	(9)	(83)
Income from continuing operations	404	128	276	806	1,217	(411)
Income from discontinued operations	9	7	2	31	6	25
Net income	$413	$135	$278	$837	$1,223	$(386)

See the detailed discussion of Segment Adjusted EBITDA below.

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

- depreciation and amortization related to Sunoco Logistics and Sunoco of $90 million; and

- additional depreciation and amortization related to assets placed in service; offset by
- a decrease of $22 million related to the contribution of SUGS to Regency on April 30, 2013.

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

- depreciation and amortization related to Southern Union, which was consolidated beginning March 26, 2012 and resulted in increased depreciation and amortization of $36 million after taking into account the contribution of SUGS on April 30, 2013;
- depreciation and amortization related to Sunoco Logistics and Sunoco of $182 million; and
- additional depreciation and amortization related to assets placed in service.

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

- interest expense related to Sunoco Logistics and Sunoco of $25 million; and
- incremental interest expense due to the issuance by ETP of $1.25 billion of Senior Notes in January 2013, offset by a reduction of several series of our higher coupon notes that were repurchased in the tender offers completed in January 2012.

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

- interest expense related to Southern Union, which was consolidated beginning March 26, 2012 and resulted in increased interest expense of $16 million;
- interest expense related to Sunoco Logistics and Sunoco of $53 million; and
- incremental interest expense due to the issuance of $1.25 billion of Senior Notes in January 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.

Gains (Losses) on Interest Rate Derivatives. Gains on interest rate derivatives during the three and six months ended June 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 three and six months ended June 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 Adjustment. A LIFO valuation reserve adjustment was recorded 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 six months ended June 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 six months ended June 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.

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

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for the six months ended June 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 six months ended June 30, 2012:

	ETP Historical	Propane Transaction (a)	Sunoco Historical (b)	Southern Union Historical (c)	Holdco Pro Forma Adjustments (d)	Pro Forma
REVENUES	$2,919	$(93)	$24,435	$443	$(9,224)	$18,480
COSTS AND EXPENSES:						
Cost of products sold and natural gas operations	1,906	(80)	22,972	313	(8,545)	16,566
Depreciation and amortization	257	(4)	112	49	48	462
Selling, general and administrative	190	(1)	309	—	(55)	443
Impairment charges	—	—	108	—	(8)	100
Total costs and expenses	2,353	(85)	23,501	362	(8,560)	17,571
OPERATING INCOME	566	(8)	934	81	(664)	909
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(332)	2	(86)	(50)	(16)	(482)
Equity in earnings of affiliates	56	3	6	16	10	91
Gain on deconsolidation of Propane Business	1,057	(1,057)	—	—	—	—
Gain (loss) on disposal of assets	(1)	2	104	—	7	112
Loss on extinguishment of debt	(115)	115	—	—	—	—
Losses on interest rate derivatives	(9)	—	—	—	—	(9)
Other, net	4	1	5	(2)	—	8
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,226	(942)	963	45	(663)	629
Income tax expense from continuing operations	9	—	333	12	(306)	48
INCOME FROM CONTINUING OPERATIONS	$1,217	$(942)	$630	$33	$(357)	$581

(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 June 30, 2012.

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

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(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.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Equity in earnings (losses) of unconsolidated affiliates:						
AmeriGas	$(20)	$(37)	$17	$43	$3	$40
Citrus	24	23	1	38	24	14
FEP	14	13	1	27	26	1
Regency	2	—	2	2	—	2
Other	17	2	15	(1)	3	(4)
Total equity in earnings of unconsolidated affiliates	$37	$1	$36	$109	$56	$53
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:						
AmeriGas	$36	$37	$(1)	$70	$72	$(2)
Citrus	55	54	1	103	57	46
FEP	5	5	—	10	11	(1)
Regency	14	—	14	14	—	14
Other	11	—	11	17	—	17
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$121	$96	$25	$214	$140	$74
Adjusted EBITDA related to unconsolidated affiliates:						
AmeriGas	$16	$—	$16	$113	$75	$38
Citrus	79	77	2	141	81	60
FEP	19	18	1	37	37	—
Regency	16	—	16	16	—	16
Other	28	2	26	16	3	13
Total Adjusted EBITDA related to unconsolidated affiliates	$158	$97	$61	$323	$196	$127
Distributions received from unconsolidated affiliates:						
AmeriGas	$24	$23	$1	$48	$46	$2
Citrus	39	25	14	63	25	38
FEP	16	17	(1)	33	35	(2)
Regency	15	—	15	15	—	15
Other	8	2	6	38	3	35
Total distributions received from unconsolidated affiliates	$102	$67	$35	$197	$109	$88

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.

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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 three months ended March 31, 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 line items are 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 above.

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 June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Natural gas transported (MMBtu/d)	9,654,524	9,928,726	(274,202)	9,682,789	10,021,540	(338,751)
Revenues	$623	$494	$129	$1,313	$976	$337
Cost of products sold	447	273	174	943	587	356
Gross margin	176	221	(45)	370	389	(19)
Unrealized (gains) losses on commodity risk management activities	(12)	(15)	3	(24)	67	(91)
Operating expenses, excluding non-cash compensation expense	(43)	(47)	4	(82)	(86)	4
Selling, general and administrative expenses, excluding non-cash compensation expense	(9)	(2)	(7)	(20)	(21)	1
Segment Adjusted EBITDA	$112	$157	$(45)	$244	$349	$(105)

Volumes. Transported volumes decreased for the three and six months ended June 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.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Transportation fees	$124	$137	$(13)	$253	$281	$(28)
Natural gas sales and other	19	33	(14)	46	47	(1)
Retained fuel revenues	26	16	10	49	33	16
Storage margin, including fees	7	35	(28)	22	28	(6)
Total gross margin	$176	$221	$(45)	$370	$389	$(19)

Intrastate transportation and storage gross margin decreased for the three months ended June 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 $7 million and $8 million during the three months ended June 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 primarily due to decreases of $12 million in margin from system optimization activities and $1 million in margin from blending, processing and wellhead sales and purchases that were sold to end users on our HPL system.
- Retained fuel revenues. Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention fuel revenue increased $10 million primarily due to an increase in the average of natural gas spot prices. The average spot price at the Houston Ship Channel for the three months ended June 30, 2013 increased to $4.00/MMBtu from $2.23/MMBtu in the same period last year. The increase in retained fuel revenues between the periods was attributable to an increase of $12 million due to price increases offset by a decrease of $2 million due to lower retention gas volumes.

Intrastate transportation and storage gross margin decreased for the six months ended June 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 $15 million during the six months ended June 30, 2013 and 2012.

- Natural gas sales and other. Margin from natural gas sales and other reflected the net impacts of a decrease of $13 million during the three months ended June 30, 2013, as discussed above, and an increase of $13 million during the three months ended March 31, 2013 primarily due to favorable variances in system optimization activities and wellhead sales and purchases.
- Retained fuel revenues. Retained fuel revenues increased $16 million primarily due to an increase in the average of natural gas spot prices. The average spot price at the Houston Ship Channel for the six months ended June 30, 2013 increased to $3.72/MMBtu from $2.32/MMBtu in the same period last year. The increase in retained fuels revenues between the periods was attributable to an increase of $20 million due to price increases offset by a decrease of $4 million due to lower retention gas volumes.

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Storage margin was comprised of the following:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Withdrawals from storage natural gas inventory (MMBtu)	—	3,893,660	(3,893,660)	11,953,718	4,440,394	7,513,324
Realized margin on natural gas inventory transactions	$(11)	$18	$(29)	$(14)	$79	$(93)
Fair value inventory adjustments	(15)	48	(63)	5	(2)	7
Unrealized gains (losses) on derivatives	26	(39)	65	17	(65)	82
Margin recognized on natural gas inventory, including related derivatives	—	27	(27)	8	12	(4)
Revenues from fee-based storage	7	8	(1)	14	16	(2)
Total storage margin	$7	$35	$(28)	$22	$28	$(6)

The decrease in storage margin for the three months ended June 30, 2013 compared to the same period last year was principally driven by an unfavorable variance from the settlement of derivatives used to hedge storage gas inventory. For the three months ended June 30, 2013, increasing prices contributed to realized losses from the settlement of storage derivatives while withdrawals were minimized primarily due to the mild spring weather. For the three months ended June 30, 2012, lower market prices contributed to realized gains from the settlement of storage derivatives with little physical offset due to the lack of withdrawals during the quarter primarily due to the unfavorable natural gas price environment.

The decrease in storage margin for the six months ended June 30, 2013 compared to the same period last year was primarily due to less physical withdrawals during the six months ended June 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 June 30, 2013, unrealized gains of $12 million primarily included unrealized gains on derivatives of $25 million, partially offset by fair value adjustments to storage gas inventory of $15 million. For the three months ended June 30, 2012, unrealized gains of $15 million primarily included unrealized gains on fair value adjustments to storage gas inventory of $48 million, partially offset by unrealized losses on derivatives of $33 million. The unrealized gains for the three months ended June 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 six months ended June 30, 2013, unrealized gains of $24 million included unrealized gains on derivatives of $18 million and fair value adjustments to storage gas inventory of $5 million. For the six months ended June 30, 2012, unrealized losses of $67 million included unrealized losses on derivatives of $65 million and fair value adjustments to storage gas inventory of $2 million. Substantially all of the $65 million in unrealized losses on derivatives for the six months ended June 30, 2012 were from derivatives related to storage natural gas inventory. The impact of unrealized losses on storage margin was offset by realized derivative gains.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased for the three and six months ended June 30, 2013 compared to the same periods last year due to decreases in operating and maintenance expenses of $5 million and $6 million, respectively, and decreases in ad valorem taxes of $1 million and $1 million, respectively, partially offset by an increase in fuel consumption of $2 million and $4 million, respectively.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage selling, general and administrative expenses increased for the three months ended June 30, 2013 compared to the same period last year primarily due to changes in employee-related costs (including allocated overhead expenses). For the six months ended June 30, 2013 compared to the same period last year, the decrease in intrastate transportation and storage selling, general and administrative expenses was primarily due to lower employee-related costs (including allocated overhead expenses) during the first quarter, which more than offset higher employee-related costs during the second quarter.

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Interstate Transportation and Storage

	Three Months Ended June 30, 2013	2012	Change	Six Months Ended June 30, 2013	2012	Change
Natural gas transported (MMBtu/d):						
ETP legacy assets	2,393,340	2,832,897	(439,557)	2,502,640	2,992,985	(490,345)
Southern Union transportation and storage	3,811,448	3,572,548	238,900	4,114,365	3,584,429	529,936
Natural gas sold (MMBtu/d) – ETP legacy assets	16,795	17,770	(975)	16,782	19,144	(2,362)
Revenues	$357	$312	$45	$681	$454	$227
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(69)	(80)	11	(141)	(112)	(29)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(25)	(30)	5	(60)	(83)	23
Adjusted EBITDA related to unconsolidated affiliates	98	95	3	178	118	60
Segment Adjusted EBITDA	$361	$297	$64	$658	$377	$281

Volumes. For the three and six months ended June 30, 2013 compared to the same periods last year, the ETP legacy assets' 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. For the Southern Union assets, transported volumes increased on a daily average basis primarily due to higher basis differentials on the Panhandle Eastern and Trunkline Gas pipelines and increased volumes from the offshore consolidation on the Sea Robin pipeline.

Revenues. Interstate transportation and storage revenues increased for the three months ended June 30, 2013 compared to the same period last year primarily due to 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 related to the Transwestern pipeline.

Interstate transportation and storage revenues increased for the six months ended June 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 $5 million related to the Transwestern and Tiger pipelines.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage operating expenses decreased for the three months ended June 30, 2013 compared to the same period last year primarily due to a decrease in operating and maintenance expenses of $7 million and lower ad valorem taxes of $4 million. For the six months ended June 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 June 30, 2013 compared to the same period last year primarily due to a decrease in employee-related costs. For the six months ended June 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 $1 million higher for the six months ended June 30, 2013 compared to the same period last year.
Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliate increased for the three months ended June 30, 2013 compared to the same period last year primarily due to increases of $2 million and $1 million from Citrus and FEP, respectively. Adjusted EBITDA related to unconsolidated affiliates increased for the six months ended

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June 30, 2013 compared to the same period last year primarily due to an increase of $60 million from Citrus. We acquired a 50% interest in Citrus on March 26, 2012.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Gathered volumes (MMBtu/d):						
ETP legacy assets	2,761,401	2,277,142	484,259	2,674,775	2,258,137	416,638
Southern Union gathering and processing	529,327	408,652	120,675	492,586	406,537	86,049
NGLs produced (Bbls/d):						
ETP legacy assets	112,951	81,676	31,275	104,927	73,652	31,275
Southern Union gathering and processing	43,777	31,060	12,717	40,705	34,891	5,814
Equity NGLs produced (Bbls/d):						
ETP legacy assets	14,854	22,255	(7,401)	12,299	19,942	(7,643)
Southern Union gathering and processing	8,216	8,081	135	7,459	8,413	(954)
Revenues	$906	$727	$179	$1,857	$1,290	$567
Cost of products sold	738	556	182	1,532	992	540
Gross margin	168	171	(3)	325	298	27
Unrealized (gains) losses on commodity risk management activities	(4)	—	(4)	(4)	2	(6)
Operating expenses, excluding non-cash compensation expense	(39)	(42)	3	(88)	(68)	(20)
Selling, general and administrative expenses, excluding non-cash compensation expense	(7)	(22)	15	(36)	(41)	5
Adjusted EBITDA attributable to discontinued operations	—	(5)	5	—	—	—
Segment Adjusted EBITDA	$118	$102	$16	$197	$191	$6

Volumes. Gathered volumes and NGL production for the ETP legacy assets increased during the three and six months ended June 30, 2013 compared to the same period last year primarily due to increased production by our customers in the Eagle Ford Shale area. Gathered volumes for Southern Union's gathering and processing operations increased during the three and six months ended June 30, 2013 compared to the same period last year primarily due to a plant expansion and improved reliability. The decrease in equity NGL production was primarily due to processing plants optimizing NGL recoveries in response to the current NGL price environment.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Gathering and processing fee-based revenues	$114	$79	$35	$211	$149	$62
Non fee-based contracts and processing	64	98	(34)	131	162	(31)
Other	(10)	(6)	(4)	(17)	(13)	(4)
Total gross margin	$168	$171	$(3)	$325	$298	$27

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Midstream gross margin decreased for the three months ended June 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 $35 million.
- Non fee-based contracts and processing. Non fee-based gross margins decreased primarily due to the contribution of Southern Union's gathering and processing operations on April 30, 2013, which resulted in a decrease of $30 million. The remainder of the decrease was due to a decline in composite NGL prices. The composite NGL price for the three months ended June 30, 2013 decreased to $0.80 per gallon from $0.94 per gallon in the same period last year.
- Other midstream gross margin. Other midstream gross margin included fees charged by our intrastate transportation systems, which were recognized as income by our intrastate transportation and storage segment and eliminated in our consolidated results of operations.

For the six months ended June 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 increased fee-based revenues of $56 million. The remainder of the increase resulted from volume increases as a result of completing our Red River gathering pipeline.
- Non fee-based contracts and processing. Non fee-based gross margins decreased primarily due to a decline in composite NGL prices. The composite NGL price for the six months ended June 30, 2013 decreased to $0.83 per gallon from $1.06 per gallon in the same period last year causing non fee-based margins to decrease by $24 million on the Southeast and North Texas assets.

Unrealized Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized gains associated with our marketing and NGL hedging activities of $4 million during the three months ended June 30, 2013 compared to unrealized gains of less than $1 million in the same period last year, primarily due to lower volumes hedged and price movements.

For the six months ended June 30, 2013, our midstream segment recorded unrealized gains of $4 million compared to unrealized losses of $2 million in the same period last year primarily due to price movements.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the three and six months ended June 30, 2013 compared to the same periods last year, the changes in operating expenses were primarily due to the consolidation of Southern Union's gathering and processing operations from March 26, 2012 through April 30, 2013. Southern Union's gathering and processing operations were consolidated during only approximately one month during the three months ended June 30, 2013, while those operations were consolidated for the entire period during the three months ended June 30, 2012. This impact was partially offset by additional expenses from assets recently placed in service. The six months ended June 30, 2013 included approximately four months of consolidation of Southern Union's gathering and processing operations, while the prior period included approximately three months. The six months ended June 30, 2013 also reflected additional expenses from assets recently placed in service.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased for the three months ended June 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 and lower allocated overhead expenses. For the six months ended June 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 transportation and storage operations for four months during the six months ended June 30, 2013 compared to only three months during the six months ended June 30, 2012.

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NGL Transportation and Services

	Three Months Ended June 30, 2013	2012	Change	Six Months Ended June 30, 2013	2012	Change
NGL transportation volumes (Bbls/d)	338,710	175,591	163,119	306,370	163,531	142,839
NGL fractionation volumes (Bbls/d)	98,915	21,204	77,711	92,843	20,606	72,237
Revenues	$438	$161	$277	$803	$328	$475
Cost of products sold	329	86	243	586	184	402
Gross margin	109	75	34	217	144	73
Unrealized gains on commodity risk management activities	(2)	—	(2)	(2)	—	(2)
Operating expenses, excluding non-cash compensation expense	(28)	(16)	(12)	(47)	(30)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(3)	(5)	2	(13)	(10)	(3)
Adjusted EBITDA related to unconsolidated affiliates	1	1	—	2	1	1
Segment Adjusted EBITDA	$77	$55	$22	$157	$105	$52

Volumes. NGL transportation volumes on our wholly-owned and joint venture NGL pipelines increased for the three and six months ended June 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 of our Jackson and Kenedy processing plants in service in February 2013 and December 2012, respectively. Average daily fractionated volumes increased for the three and six months ended June 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 June 30, 2013	2012	Change	Six Months Ended June 30, 2013	2012	Change
Storage margin	$34	$30	$4	$66	$62	$4
Transportation margin	45	18	27	86	31	55
Processing and fractionation margin	30	27	3	64	51	13
Other margin	—	—	—	1	—	1
Total gross margin	$109	$75	$34	$217	$144	$73

NGL transportation and services gross margin increased for the three and six months ended June 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 $18 million and $39 million for the three and six months ended June 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 six months ended June 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 $18 million and $34 million for three and six months ended June 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 a less favorable pricing environment, lower volumes and a less favorable contract mix.

Operating Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services operating expenses increased for the three and six months ended June 30, 2013 compared to the same periods last year primarily due to increases of $5 million

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and $8 million, respectively, in operating expenses related to the start-up of Lone Star's fractionator and increases of $4 million and $7 million, respectively, in ad valorem taxes.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services selling, general and administrative expenses decreased for the three months ended June 30, 2013 compared to the same period last year primarily due to a decrease in employee-related costs. For the six months ended June 30, 2013 compared to the same period last year, NGL transportation and services selling, general and administrative expenses increased primarily due to an increase in allocated overhead expenses due to the overall asset growth on the system.

Investment in Sunoco Logistics

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Revenue	$4,311	$—	$4,311	$7,823	$—	$7,823
Cost of products sold	4,023	—	4,023	7,247	—	7,247
Gross margin	288	—	288	576	—	576
Unrealized gains on commodity risk management activities	(1)	—	(1)	(4)	—	(4)
Operating expenses, excluding non-cash compensation expense	(25)	—	(25)	(51)	—	(51)
Selling, general and administrative expenses, excluding non-cash compensation expense	(29)	—	(29)	(59)	—	(59)
Adjusted EBITDA related to unconsolidated affiliates	11	—	11	18	—	18
Segment Adjusted EBITDA	$244	$—	$244	$480	$—	$480

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.

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Retail Marketing

	Three Months Ended June 30, 2013	2012	Change	Six Months Ended June 30, 2013	2012	Change
Total retail gasoline outlets, end of period	4,974	—	4,974	4,974	—	4,974
Total company-operated outlets, end of period	440	—	440	440	—	440
Gasoline and diesel throughput per company-operated site (gallons/month)	204,320	—	204,320	195,710	—	195,710
Revenue	$5,291	$—	$5,291	$10,513	$—	$10,513
Cost of products sold	5,087	—	5,087	10,123	—	10,123
Gross margin	204	—	204	390	—	390
Operating expenses, excluding non-cash compensation expense	(106)	—	(106)	(204)	—	(204)
Selling, general and administrative expenses, excluding non-cash compensation expense	(23)	—	(23)	(38)	—	(38)
LIFO valuation adjustment	22	—	22	(16)	—	(16)
Adjusted EBITDA related to unconsolidated affiliates	1	—	1	3	—	3
Other	(1)	—	(1)	(1)	—	(1)
Segment Adjusted EBITDA	$97	$—	$97	$134	$—	$134

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 June 30, 2013	2012	Change	Six Months Ended June 30, 2013	2012	Change
Revenue	$101	$86	$15	$251	$215	$36
Cost of products sold	76	64	12	213	155	58
Gross margin	25	22	3	38	60	(22)
Unrealized (gains) losses on commodity risk management activities	1	—	1	(3)	2	(5)
Operating expenses, excluding non-cash compensation expense	(6)	(4)	(2)	(11)	(24)	13
Selling, general and administrative expenses, excluding non-cash compensation expense	(19)	(16)	(3)	(37)	(29)	(8)
Adjusted EBITDA attributable to discontinued operations	23	32	(9)	63	34	29
Adjusted EBITDA related to unconsolidated affiliates	49	1	48	125	76	49
Other	(11)	—	(11)	(11)	—	(11)
Elimination	(2)	(4)	2	(9)	(5)	(4)

Segment Adjusted EBITDA	$60	$31	$29	$155	$114	$41

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Amounts reflected in our all other segment primarily include:

- Our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas in January 2012. Our investment in AmeriGas was reflected in the all other segment subsequent to that transaction;
- Southern Union's local distribution operations beginning March 26, 2012;
- Our natural gas 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 six months ended June 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.

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
ETP legacy assets:				
Intrastate transportation and storage	$10	$10	$20	$25
Interstate transportation and storage	15	20	25	30
Midstream	360	380	45	50
NGL transportation and services[1]	445	465	15	20
	830	875	105	125
Holdco:				
Southern Union transportation and storage	20	30	75	80
Southern Union gathering and processing	95	95	10	10
Retail marketing	50	70	70	85
	165	195	155	175
Investment in Sunoco Logistics	685	710	60	65
All other (including eliminations)	(10)	(10)	40	70
Total projected capital expenditures	$1,670	$1,770	$360	$435

(1) We expect to receive capital contributions from Regency related to their 30% share of Lone Star of $60 million.

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.

Six months ended June 30, 2013 compared to six months ended June 30, 2012. Cash provided by operating activities during 2013 was $1.16 billion compared to $469 million for 2012 and net income was $837 million and $1.22 billion for 2013 and 2012, respectively. The difference between net income and cash provided by operating activities for the six months ended June 30, 2013 primarily consisted of net changes in operating assets and liabilities of $277 million and non-cash items totaling $456 million.

The non-cash activity in 2013 and 2012 consisted primarily of depreciation and amortization of $511 million and $257 million, respectively, and non-cash compensation expense of $24 million and $21 million, respectively.

Cash paid for interest, net of interest capitalized, was $448 million and $273 million for the six months ended June 30, 2013 and 2012, respectively.

Capitalized interest for the six months ended June 30, 2013 was $17 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 the contributions of SUGS and the Propane Business in 2013 and 2012, respectively. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Six months ended June 30, 2013 compared to six months ended June 30, 2012. Cash used in investing activities during 2013 was $1.93 billion compared to $1 billion for 2012. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2013 were $1.13 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2012 of $1.10 billion. Additional detail related to our capital expenditures is provided in the table below. In 2013, we received $493 million in cash from the SUGS

Contribution and paid net cash for acquisitions of $1.34 billion, 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.

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The following is a summary of capital expenditures for the six months ended June 30, 2013:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
ETP legacy assets:					
Intrastate transportation and storage	$7	$15	$22	$(13)	$9
Interstate transportation and storage	9	14	23	14	37
Midstream	231	17	248	33	281
NGL transportation and services	226	9	235	10	245
	473	55	528	44	572
Holdco:					
Southern Union transportation and storage	11	19	30	(4)	26
Southern Union gathering and processing	95	10	105	11	116
Retail marketing	15	32	47	14	61
	121	61	182	21	203
Investment in Sunoco Logistics	310	22	332	(12)	320
All other (including eliminations)	(5)	34	29	7	36
Total	$899	$172	$1,071	$60	$1,131

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.

Six months ended June 30, 2013 compared to six months ended June 30, 2012. Cash provided by financing activities during 2013 was $985 million compared to $625 million for 2012. In 2013, we received net proceeds from Common Unit offerings of $1.09 billion compared to $94 million in 2012. During 2013, we had a net increase in our debt level of $962 million compared to a net increase of $1.05 billion for 2012. We incurred debt issuance costs of $19 million in 2013 compared to $20 million in 2012. We paid distributions of $873 million to our partners in 2013 compared to $628 million in 2012. We also paid distributions of $247 million to noncontrolling interests in 2013 compared to $18 million in 2012. In addition, we received capital contributions of $72 million from Regency for its noncontrolling interest in Lone Star compared to $151 million in 2012.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 2013	December 31, 2012
ETP Debt	$10,912	$9,073
Transwestern Debt	869	869
Southern Union Debt	226	1,526
Panhandle Debt	1,740	1,757
Sunoco Debt	1,077	1,094
Sunoco Logistics Debt	2,314	1,732
Note Payable to ETE	—	166
Total	17,138	16,217
Less: current maturities	(895)	(609)
Long-term debt and notes payable, less current maturities	$16,243	$15,608

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.

Credit Facilities

ETP Credit Facility

ETP has a $2.5 billion revolving credit facility, the ETP Credit Facility, that 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.

As of June 30, 2013, we had $900 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.49 billion after taking into account letters of credit of $107 million. The weighted average interest rate on the total amount outstanding as of June 30, 2013 was 1.70%.

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 2013. There were no outstanding borrowings under these facilities as of June 30, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving credit facility. Outstanding borrowings under this credit facility were $35 million as of June 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 June 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.

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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

The total amounts of distributions declared during the six months ended June 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):

	Six Months Ended June 30,	
	2013	2012
Limited Partners:		
Common Units held by public	$487	$335
Common Units held by ETE	178	90
General Partner interests held by ETE	10	10
IDRs held by ETE	363	234
IDR relinquishment related to previous acquisitions	(86)	(28)
Total distributions declared to the partners of ETP	$952	$641

The distributions reflected above for the six months ended June 30, 2013 reflect IDR reductions totaling $86 million, which includes two quarters of IDR relinquishment related to the Citrus Merger, two quarters of IDR relinquishment related to the Holdco Transaction and one quarter of IDR relinquishment related to the Holdco Acquisition. The distributions reflected above for the six months ended June 30, 2012 reflect IDR reductions totaling $28 million, which includes two quarters of IDR relinquishment related to the Citrus Merger.

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 of $329 million over 15 quarters, commencing with the quarter ending 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

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Cash Distributions Paid by Sunoco Logistics

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

Following are distributions declared and/or paid by Sunoco Logistics 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

The total amounts of Sunoco Logistics distributions declared during the six months ended June 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):

	Six Months Ended June 30,
Limited Partners:	
Common Units	$121
General Partner interest	2
IDRs	53
Total distributions declared	$176

Sunoco Logistics declared $94 million in cash distributions to us for the six months ended June 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 June 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.

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	June 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	9,650,000	$(3)	$—	—	$—	$—
Basis Swaps IFERC/NYMEX [1]	(37,702,500)	(3)	4	(30,980,000)	(6)	—
Power (Megawatt):						
Forwards	145,078	—	1	19,650	—	1
Futures	(557,260)	—	1	(1,509,300)	(1)	1
Options — Calls	(1,200)	3	1	1,656,400	2	1
Crude (Bbls) — Futures	(80,000)	—	1	—	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	8,770,000	(1)	—	150,000	(1)	—
Swing Swaps IFERC	20,060,000	(1)	—	(83,292,500)	1	1
Fixed Swaps/Futures	23,435,000	1	16	27,077,500	(7)	9
Forward Physical Contracts	1,758,402	1	—	11,689,855	—	2
Natural Gas Liquid (Bbls):						
Forwards/Swaps	(597,000)	2	1	(30,000)	—	—
Refined Products (Bbls) — Futures	(1,227,000)	1	14	(666,000)	(3)	14
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(10,530,000)	—	—	(18,655,000)	(1)	—
Fixed Swaps/Futures	(32,682,500)	12	13	(44,272,500)	4	15
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(2,300,000)	—	—	—	—	—
Fixed Swaps/Futures	(4,140,000)	1	2	(8,212,500)	(3)	3
Natural Gas Liquid (Bbls):						
Forwards/Swaps	(690,000)	6	4	(930,000)	(2)	7
Refined Products (Bbls) — Futures	—	—	—	(98,000)	—	1
Crude (Bbls) — Futures	(210,000)	(1)	2	—	—	—

(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

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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 June 30, 2013, we had $2 billion of floating rate debt outstanding under our revolving credit facility. A hypothetical change of 100 basis points would result in a change to interest expense of $20 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

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

Entity	Term	Type [1]	Notional Amount Outstanding June 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	$100	$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	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 2.91% and receive a floating rate	75	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.

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 $24 million as of June 30, 2013. For the $1 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 $10 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 sheet and recognized in net income or other comprehensive income.

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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 June 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 June 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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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 June 30, 2013.

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.

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ITEM 6. EXHIBITS

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

	Exhibit Number	Description
(*)	3.1	Amendment No. 4, dated April 30, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended.
(**)	3.2	Amendment No. 3, dated April 15, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended.
(*)	4.1	Registration Rights Agreement, dated April 30, 2013, by and between Southern Union Company and Regency Energy Partners LP
(*)	4.2	Registration Rights Agreement, dated April 30, 2013, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(*)	10.1	First Amendment, dated April 30, 2013, to the Services Agreement, effective as of May 26, 2010, by and among Energy Transfer Equity, L.P., ETE Services Company LLC and Regency Energy Partners LP.
(*)	10.2	Second Amendment , dated April 30, 2013, to the Operation and Service Agreement, dated May 19, 2011, as amended, by and among La Grange Acquisition, L.P. d/b/a Energy Transfer Company, Regency Energy Partners LP, Regency GP LP and Regency Gas Services LP.
(*)	10.3	Guarantee of Collection, dated as of April 30, 2013, by and between Regency Energy Partners LP, PEPL Holdings, LLC and Regency Energy Finance Corp.
(*)	10.4	Second Amendment, dated April 30, 2013, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010, by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P.
	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 May 1, 2013.

** Indicates exhibit incorporated by reference to Energy Transfer Partners, L.P. Current Report on Form 8-K/A filed on April 18, 2013.

*** Furnished herewith.

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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: August 8, 2013

By: /s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer (duly authorized to sign on behalf of the registrant)