Energy Transfer Partners, L.P.
Form 10-Q
August 07, 2014

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, 2014

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 1, 2014, the registrant had 325,444,109 Common Units outstanding.

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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. (the “Partnership,” or “ETP”) in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “estimate,” “goal,” “ “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, 2013 filed with the Securities and Exchange Commission on February 27, 2014.

Definitions

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

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Bbls	barrels
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
Citrus	Citrus Corp.
CrossCountry	CrossCountry Energy, LLC
ET Crude Oil	Energy Transfer Crude Oil Company, LLC, a joint venture owned 60% by ETE and 40% by ETP
ETC Compression	ETC Compression, LLC
ETC FEP	ETC Fayetteville Express Pipeline, LLC

ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP Credit Facility	ETP's $2.5 billion revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC

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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
MACS	Mid-Atlantic Convenience Stores, LLC
MMBtu	million British thermal units
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP
PCBs	polychlorinated biphenyls
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, a subsidiary of Panhandle
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.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle
Trunkline LNG	Trunkline LNG Company, LLC, a subsidiary of ETE

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

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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, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,120	$549
Accounts receivable, net	3,983	3,359
Accounts receivable from related companies	255	165
Inventories	1,496	1,765
Exchanges receivable	81	56
Price risk management assets	12	35
Other current assets	266	310
Total current assets	7,213	6,239
PROPERTY, PLANT AND EQUIPMENT	29,379	28,430
ACCUMULATED DEPRECIATION	(2,888)	(2,483)
	26,491	25,947
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,850	4,436
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	—	17
GOODWILL	4,521	4,729
INTANGIBLE ASSETS, net	1,512	1,568
OTHER NON-CURRENT ASSETS, net	636	766
Total assets	$44,223	$43,702

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, 2014	December 31, 2013
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$4,070	$3,627
Accounts payable to related companies	88	45
Exchanges payable	271	285
Price risk management liabilities	58	45
Accrued and other current liabilities	1,682	1,428
Current maturities of long-term debt	1,346	637
Total current liabilities	7,515	6,067
LONG-TERM DEBT, less current maturities	16,220	16,451
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	69	54
DEFERRED INCOME TAXES	3,612	3,762
OTHER NON-CURRENT LIABILITIES	1,037	1,080
COMMITMENTS AND CONTINGENCIES (Note 13)		
REDEEMABLE NONCONTROLLING INTERESTS	15	—
EQUITY:		
General Partner	171	171
Limited Partners:		
Common Unitholders	9,089	9,797
Class H Unitholder	1,504	1,511
Accumulated other comprehensive income	52	61
Total partners’ capital	10,816	11,540
Noncontrolling interest	4,939	4,748
Total equity	15,755	16,288
Total liabilities and equity	$44,223	$43,702

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,	
	2014	2013	2014	2013
REVENUES:				
Natural gas sales	$908	$691	$2,011	$1,565
NGL sales	1,015	588	1,966	1,177
Crude sales	4,432	3,992	8,525	7,193
Gathering, transportation and other fees	601	692	1,256	1,329
Refined product sales	4,938	4,650	9,416	9,312
Other	1,135	938	2,087	1,829
Total revenues	13,029	11,551	25,261	22,405
COSTS AND EXPENSES:				
Cost of products sold	11,636	10,229	22,502	19,823
Operating expenses	308	327	627	654
Depreciation and amortization	268	251	534	511
Selling, general and administrative	81	112	174	251
Total costs and expenses	12,293	10,919	23,837	21,239
OPERATING INCOME	736	632	1,424	1,166
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(217)	(211)	(436)	(422)
Equity in earnings of unconsolidated affiliates	57	37	136	109
Gain on sale of AmeriGas common units	93	—	163	—
Gains (losses) on interest rate derivatives	(46)	39	(48)	46
Other, net	(14)	(4)	(17)	(1)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	609	493	1,222	898
Income tax expense from continuing operations	70	89	216	92
INCOME FROM CONTINUING OPERATIONS	539	404	1,006	806
Income from discontinued operations	42	9	66	31
NET INCOME	581	413	1,072	837
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	110	93	186	195
NET INCOME ATTRIBUTABLE TO PARTNERS	471	320	886	642
GENERAL PARTNER’S INTEREST IN NET INCOME	125	155	238	283
CLASS H UNITHOLDER’S INTEREST IN NET INCOME	51	—	100	—
COMMON UNITHOLDERS’ INTEREST IN NET INCOME	$295	$165	$548	$359
INCOME FROM CONTINUING OPERATIONS PER COMMON UNIT:				
Basic	$0.79	$0.52	$1.47	$1.04
Diluted	$0.79	$0.52	$1.47	$1.04
NET INCOME PER COMMON UNIT:				
Basic	$0.92	$0.53	$1.67	$1.08

Diluted	$0.92	$0.53	$1.67	$1.08

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,	
	2014	2013	2014	2013
Net income	$581	$413	$1,072	$837
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	2	(1)	6	(2)
Change in value of derivative instruments accounted for as cash flow hedges	(2)	6	(6)	8
Change in value of available-for-sale securities	—	(1)	—	—
Actuarial gain (loss) relating to pension and other postretirement benefits	—	2	(1)	1
Foreign currency translation adjustment	1	—	(2)	(1)
Change in other comprehensive income from unconsolidated affiliates	1	(3)	(6)	4
	2	3	(9)	10
Comprehensive income	583	416	1,063	847
Less: Comprehensive income attributable to noncontrolling interest	110	91	186	192
Comprehensive income attributable to partners	$473	$325	$877	$655

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, 2014
(Dollars in millions)
(unaudited)

		Limited Partners				
	General Partner	Common Units	Class H Units	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance, December 31, 2013	$171	$9,797	$1,511	$ 61	$ 4,748	$16,288
Distributions to partners	(238)	(602)	(103)	—	—	(943)
Distributions to noncontrolling interest	—	—	—	—	(157)	(157)
Units issued for cash	—	484	—	—	—	484
Subsidiary units issued for cash	—	14	—	—	88	102
Capital contributions from noncontrolling interest	—	—	—	—	71	71
Trunkline LNG Transaction (see Note 2)	—	(1,167)	—	—	—	(1,167)
Other comprehensive loss, net of tax	—	—	—	(9)	—	(9)
Other, net	—	15	(4)	—	3	14
Net income	238	548	100	—	186	1,072
Balance, June 30, 2014	$171	$9,089	$1,504	$ 52	$ 4,939	$15,755

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

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

	Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$1,072	$837
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	534	511
Deferred income taxes	(111)	73
Amortization included in interest expense	(34)	(47)
LIFO valuation adjustments	(34)	(16)
Non-cash compensation expense	27	24
Gain on sale of AmeriGas common units	(163)	—
Distributions on unvested awards	(8)	(6)
Equity in earnings of unconsolidated affiliates	(136)	(109)
Distributions from unconsolidated affiliates	108	154
Other non-cash	(33)	20
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 3)	351	(277)
Net cash provided by operating activities	1,573	1,164
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash proceeds from SUGS Contribution (see Note 2)	—	493
Cash paid for Holdco Acquisition	—	(1,332)
Cash paid for all other acquisitions	(196)	(5)
Cash proceeds from the sale of AmeriGas common units	759	—
Capital expenditures (excluding allowance for equity funds used during construction)	(1,700)	(1,131)
Contributions in aid of construction costs	25	11
Contributions to unconsolidated affiliates	(63)	(1)
Distributions from unconsolidated affiliates in excess of cumulative earnings	65	43
Proceeds from sale of discontinued operations	79	—
Proceeds from the sale of assets	12	19
Other	7	(25)
Net cash used in investing activities	(1,012)	(1,928)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	2,993	3,960
Repayments of long-term debt	(2,544)	(2,832)
Repayments of borrowings from affiliates	—	(166)
Net proceeds from issuance of Common Units	484	1,090
Subsidiary equity offerings, net of issue costs	102	—
Capital contributions received from noncontrolling interest	84	72
Distributions to partners	(943)	(873)
Distributions to noncontrolling interest	(157)	(247)
Debt issuance costs	(9)	(19)
Net cash provided by financing activities	10	985
INCREASE IN CASH AND CASH EQUIVALENTS	571	221
CASH AND CASH EQUIVALENTS, beginning of period	549	311

CASH AND CASH EQUIVALENTS, end of period	$1,120	$532

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 master limited partnership, and its subsidiaries (collectively, 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 primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. ETC OLP’s intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP’s midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns 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.
- Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco. Panhandle and Sunoco operations are described as follows:
- Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. As discussed in Note 2, in January 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle surviving the merger.
- Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail locations and operates convenience stores primarily on the east coast and in the midwest region of the United States. Effective June 1, 2014, the Partnership combined certain Sunoco retail assets with another wholly-owned subsidiary of ETP to form a limited liability company owned by ETP and its wholly-owned subsidiary, Sunoco.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products, crude oil and NGL pipelines, terminalling and storage assets, and refined products, crude oil and NGL acquisition and marketing assets.

Our financial statements reflect the following reportable business segments:

- intrastate transportation and storage;

•interstate transportation and storage;

- midstream;
- NGL transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

Preparation of Interim Financial Statements

The accompanying consolidated balance sheet as of December 31, 2013, 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, 2014 and for the three and six months ended June 30, 2014 and 2013 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, 2014, and the Partnership’s results of operations and cash flows for the three and six months ended June 30, 2014 and 2013. The unaudited interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto presented in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the SEC on February 27, 2014.

Certain prior period amounts have been reclassified to conform to the 2014 presentation. These reclassifications had no impact on net income or total equity.

We record the collection of taxes to be remitted to government authorities on a net basis except for our retail marketing segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and cost of products sold in the consolidated statements of operations, with no net impact on net income. Excise taxes collected by our retail marketing segment were $573 million and $563 million for the three months ended June 30, 2014 and 2013, respectively, and $1.10 billion and $1.08 billion for the six months ended June 30, 2014 and 2013, respectively.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (“ASU 2014-08”), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity’s operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

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2. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2014

Susser Holdings Merger

On April 27, 2014, ETP entered into a definitive merger agreement whereby ETP plans to acquire Susser Holdings Corporation ("Susser Holdings") in a unit and cash transaction for total consideration valued at approximately $1.8 billion (the "Susser Merger"). By acquiring Susser Holdings, ETP will own the general partner interest and the incentive distribution rights in Susser Petroleum Partners LP ("Susser Petroleum"), approximately 11 million Susser Petroleum common units (representing approximately 50.2% of Susser Petroleum's outstanding units), and Susser Holdings' existing retail operations, consisting of 630 convenience store locations. The Susser Merger is expected to close in the third quarter of 2014, subject to approval of the shareholders of Susser Holdings.

Trunkline LNG Transaction

On February 19, 2014, ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE (the "Trunkline LNG Transaction"). This transaction was effective as of January 1, 2014, at which time ETP deconsolidated Trunkline LNG, including goodwill of $184 million and intangible assets of $50 million related to Trunkline LNG. The results of Trunkline LNG's operations have not been presented as discontinued operations and Trunkline LNG's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements due to the continuing involvement among the entities.

In connection with ETE's acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG's regasification facility and the development of a liquefaction project at Trunkline LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions, as discussed further in Note 10.

Panhandle Merger

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

2013

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings 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 Partnership's 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.

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Discontinued Operations

Discontinued operations for the six months ended June 30, 2014 included the results of operations for a marketing business that had been recently acquired and was sold effective April 1, 2014, as well as a $39 million gain on the sale. The disposed subsidiary's results of operations were not material during any periods in 2013; therefore, the disposed subsidiary's results were not reclassified to discontinued operations in the prior period.

Discontinued operations for the three and six months ended June 30, 2013 included the results of Southern Union's distribution operations.

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 (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Six Months Ended June 30, 2014	2013
Accounts receivable	$(778)	$(206)
Accounts receivable from related companies	(90)	(63)
Inventories	310	(64)
Exchanges receivable	(31)	(5)
Other current assets	193	72
Other non-current assets, net	(25)	(32)
Accounts payable	563	177
Accounts payable to related companies	47	(65)
Exchanges payable	(12)	(2)
Accrued and other current liabilities	147	48
Other non-current liabilities	(44)	(34)
Price risk management assets and liabilities, net	71	(103)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$351	$(277)

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2014	2013
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$291	$405
Regency common units and Class F units received in exchange for contribution of SUGS	$—	$961
Net gains from subsidiary common unit issuances	$14	$—
NON-CASH FINANCING ACTIVITIES:		
Issuance of Common Units in connection with the Holdco Acquisition	$—	$2,464
Redemption of Common Units in connection with the Trunkline LNG Transaction (see Note 2)	$1,167	$—

4. INVENTORIES:

Inventories consisted of the following:

	June 30, 2014	December 31, 2013
Natural gas and NGLs	$258	$519
Crude oil	478	488
Refined products	583	597
Appliances, parts and fittings and other	177	161
Total inventories	$1,496	$1,765

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

5. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

AmeriGas Partners, L.P.

In January 2014, June 2014 and August 2014, we sold 9.2 million, 8.5 million and 1.2 million AmeriGas common units, respectively, for net proceeds of $381 million, $377 million and $55 million, respectively. Net proceeds from these sales were used to repay borrowings under the ETP Credit Facility and for general partnership purposes. Subsequent to the August 2014 sale, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Bayview Refining Company, LLC

In May 2014, Sunoco Logistics entered into a joint agreement to form Bayview Refining Company, LLC ("Bayview"). Bayview will construct and operate a facility that will process crude oil into intermediate petroleum products. Sunoco Logistics will fund construction of the facility through contributions proportionate to its 49% economic and voting interests, with the remaining portion funded by the joint owner through a promissory note entered into with Sunoco Logistics. Through June 30, 2014, the joint owners have made contributions totaling $8 million. The facility is expected to commence operations in the second half of 2015. Bayview is a variable interest entity of which Sunoco Logistics is not the primary beneficiary. As a result, Sunoco Logistics' interest in Bayview is reflected as an equity method investment.

6. FAIR VALUE MEASUREMENTS:

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the six months ended June 30, 2014, 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, 2014 and December 31, 2013 was $19.12 billion and $17.69 billion, respectively. As of June 30, 2014 and December 31, 2013, the aggregate carrying amount of our consolidated debt obligations was $17.57 billion and $17.09 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, 2014 and December 31, 2013 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2014	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$3	$—	$3
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	7	7	—
Swing Swaps IFERC	2	2	—
Fixed Swaps/Futures	35	35	—
Power:			
Forwards	8	—	8
Futures	4	4	—
Natural Gas Liquids – Forwards/Swaps	7	7	—
Refined Products – Futures	5	5	—
Total commodity derivatives	68	60	8
Total assets	$71	$60	$11
Liabilities:			
Interest rate derivatives	$(121)	$—	$(121)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(7)	(7)	—
Swing Swaps IFERC	(2)	(2)	—
Fixed Swaps/Futures	(42)	(42)	—
Power:			
Forwards	(6)	—	(6)
Futures	(4)	(4)	—
Natural Gas Liquids – Forwards/Swaps	(14)	(14)	—
Refined Products – Futures	(7)	(7)	—
Total commodity derivatives	(82)	(76)	(6)
Total liabilities	$(203)	$(76)	$(127)

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	Fair Value Total	Fair Value Measurements at December 31, 2013 Level 1	Level 2
Assets:			
Interest rate derivatives	$47	$—	$47
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	5	5	—
Swing Swaps IFERC	8	1	7
Fixed Swaps/Futures	201	201	—
Power – Forwards	3	—	3
Natural Gas Liquids – Forwards/Swaps	5	5	—
Refined Products – Futures	5	5	—
Total commodity derivatives	227	217	10
Total assets	$274	$217	$57
Liabilities:			
Interest rate derivatives	$(95)	$—	$(95)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(4)	(4)	—
Swing Swaps IFERC	(6)	—	(6)
Fixed Swaps/Futures	(201)	(201)	—
Forward Physical Swaps	(1)	—	(1)
Power – Forwards	(1)	—	(1)
Natural Gas Liquids – Forwards/Swaps	(5)	(5)	—
Refined Products – Futures	(5)	(5)	—
Total commodity derivatives	(223)	(215)	(8)
Total liabilities	$(318)	$(215)	$(103)

7. NET INCOME PER LIMITED PARTNER UNIT:

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

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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,	
	2014	2013	2014	2013
Income from continuing operations	$539	$404	$1,006	$806
Less: Income from continuing operations attributable to noncontrolling interest	110	89	186	178
Income from continuing operations, net of noncontrolling interest	429	315	820	628
General Partner’s interest in income from continuing operations	125	154	238	282
Class H Unitholder’s interest in income from continuing operations	51	—	100	—
Common Unitholders’ interest in income from continuing operations	253	161	482	346
Additional earnings allocated from (to) General Partner	1	23	(2)	—
Distributions on employee unit awards, net of allocation to General Partner	(3)	(2)	(6)	(5)
Income from continuing operations available to Common Unitholders	$251	$182	$474	$341
Weighted average Common Units – basic	318.5	352.6	321.4	326.9
Basic income from continuing operations per Common Unit	$0.79	$0.52	$1.47	$1.04
Dilutive effect of unvested Unit Awards	1.0	1.2	1.0	1.2
Weighted average Common Units, assuming dilutive effect of unvested Unit Awards	319.5	353.8	322.4	328.1
Diluted income from continuing operations per Common Unit	$0.79	$0.52	$1.47	$1.04
Basic income from discontinued operations per Common Unit	$0.13	$0.01	$0.20	$0.04
Diluted income from discontinued operations per Common Unit	$0.13	$0.01	$0.20	$0.04

8. DEBT OBLIGATIONS:

Senior Notes

In April 2014, Sunoco Logistics issued $300 million aggregate principal amount of 4.25% Senior Notes due April 2024 and $700 million aggregate principal amount of 5.30% Senior Notes due April 2044. The net proceeds from the offering were used to pay outstanding borrowings under the Sunoco Logistics Credit Facility and for general partnership purposes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our current and future unsecured debt. As of June 30, 2014, the ETP Credit Facility had no outstanding borrowings.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $1.5 billion unsecured credit facility (the “Sunoco Logistics Credit Facility”), which matures in November 2018. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $2.25 billion under certain conditions. As of June 30, 2014, the Sunoco Logistics Credit Facility had $250 million outstanding.

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Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of June 30, 2014.

9. REDEEMABLE NONCONTROLLING INTERESTS:

The noncontrolling interest holders in one of Sunoco Logistics' consolidated subsidiaries have the option to sell their interests to Sunoco Logistics. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable interest on ETP's consolidated balance sheet as of June 30, 2014.

10. EQUITY:

Common Units

The change in Common Units during the six months ended June 30, 2014 was as follows:

	Number of Units
Number of Common Units at December 31, 2013	333.8
Common Units issued in connection with Equity Distribution Agreements	7.6
Common Units issued in connection with the Distribution Reinvestment Plan	1.3
Common Units redeemed in connection with the Trunkline LNG Transaction	(18.7)
Number of Common Units at June 30, 2014	324.0

During the six months ended June 30, 2014, we received proceeds of $417 million, net of commissions of $4 million, from the issuance of units pursuant to equity distribution agreements, which were used for general partnership purposes. As of June 30, 2014, approximately $725 million of our Common Units remained available to be issued under our currently effective equity distribution agreement, which was entered into in May 2014.

During the six months ended June 30, 2014, distributions of $67 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 1.3 million Common Units. As of June 30, 2014, a total of 0.8 million Common Units remain available to be issued under the existing registration statement.

As discussed in Note 2, ETP redeemed and cancelled 18.7 million of its Common Units in connection with the Trunkline LNG Transaction.

Sales of Common Units by Subsidiaries

We account for the difference between the carrying amount of our investment in Sunoco Logistics and the underlying book value arising from the issuance or redemption of units by Sunoco Logistics (excluding transactions with us) as capital transactions.

As a result of Sunoco Logistics' issuances of common units during the six months ended June 30, 2014, we recognized increases in partners' capital of $14 million.

Sales of Common Units by Sunoco Logistics

In May 2014, Sunoco Logistics entered into an equity distribution agreement pursuant to which Sunoco Logistics may sell from time to time common units having aggregate offering prices of up to $250 million. During the six months ended June 30, 2014, Sunoco Logistics received proceeds of $102 million, net of commissions of $1 million, from the issuance of units pursuant to the equity distribution agreement, which were used for general partnership purposes. As of June 30, 2014, approximately $147 million of Sunoco Logistics' common units remained available to be issued under this agreement.

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Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by ETP subsequent to December 31, 2013:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2013	February 7, 2014	February 14, 2014	$0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550

In connection with previous transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods, and ETP has agreed to make incremental distributions on the Class H Units in future periods. The net impact of these adjustments resulted in a reduction of $53 million in the distributions to be paid from ETP to ETE for the six months ended June 30, 2014. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods:

	Total Year
2014 (remainder)	$53
2015	51
2016	72
2017	50
2018	45
2019	35

In addition to the amounts reflected above, ETE has agreed, upon closing of the Susser Merger, to amend the ETP partnership agreement to provide for, among other things, the relinquishment of $350 million in the aggregate of incentive distributions that would potentially be made to ETE over the first forty fiscal quarters commencing immediately after the consummation of the merger. Such relinquishments would cease upon the agreement of an exchange of the Susser Petroleum general partner interest and the incentive distribution rights between ETE and ETP.

Sunoco Logistics Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2013:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2013	February 10, 2014	February 14, 2014	$0.3313
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650

Sunoco Logistics Unit Split

On May 5, 2014, Sunoco Logistics’ board of directors declared a two-for-one split of Sunoco Logistics common units. The unit split resulted in the issuance of one additional Sunoco Logistics common unit for every one unit owned as of the close of business on June 5, 2014. The unit split was effective June 12, 2014. All Sunoco Logistics unit and per unit information included in this report is presented on a post-split basis.

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Accumulated Other Comprehensive Income (Loss)

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

	June 30, 2014	December 31, 2013
Available-for-sale securities	$2	$2
Foreign currency translation adjustment	(3)	(1)
Net loss on commodity related hedges	(4)	(4)
Actuarial gain related to pensions and other postretirement benefits	55	56
Investments in unconsolidated affiliates, net	2	8
Total AOCI, net of tax	$52	$61

11. INCOME TAXES:

Income tax expense from continuing operations for the six months ended June 30, 2014 included the impact of the Trunkline LNG Transaction, which was treated as a sale for tax purposes, resulting in $87 million of incremental income tax expense.

12. 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,			
	2014		2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$1	$—	$3	$1
Interest cost	7	2	9	1
Expected return on plan assets	(9)	(2)	(15)	(1)
Settlement credits	(1)	—	—	—
	(2)	—	(3)	1
Regulatory adjustment	—	—	2	—
Net periodic benefit cost	$(2)	$—	$(1)	$1

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	Six Months Ended June 30, 2014		2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$1	$—	$5	$1
Interest cost	15	3	18	3
Expected return on plan assets	(20)	(4)	(30)	(4)
Actuarial loss amortization	(1)	—	1	—
Settlement credits	(2)	—	(2)	—
	(7)	(1)	(8)	—
Regulatory adjustment	—	—	4	—
Net periodic benefit cost	$(7)	$(1)	$(4)	$—

Panhandle has historically recovered 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 reflected in expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

Panhandle no longer has pension plans after the sale of the assets of Missouri Gas Energy and New England Gas Company in 2013.

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

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Certain FDOT/FTE projects have been or are the subject of litigation in Broward County, Florida. On November 16, 2012, FDOT paid to FGT the sum of approximately $100 million, representing the amount of the judgment, plus interest, in a case tried in 2011.

On April 14, 2011, FGT filed suit against the FDOT/FTE and other defendants in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in FGT easements as part of FDOT/FTE's I-595 project. On August 21, 2013, FGT and FDOT/FTE entered into a settlement agreement pursuant to which, among other things, FDOT/FTE paid FGT approximately $19 million in September 2013 in settlement of FGT's claims with respect to the I-595 project. The settlement agreement also provided for agreed easement widths for FDOT/FTE right-of-way and for cost sharing between FGT and FDOT/FTE for any future relocations. Also in September 2013, FDOT/FTE paid FGT an additional approximate $1 million for costs related to the aforementioned turnpike/State Road 91 case tried in 2011.

FGT will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that FGT will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate FGT for its costs.

Contingent Residual Support Agreement – AmeriGas

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

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PEPL Holdings Guarantee of Collection
In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the “Regency Debt”), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. In connection with the closing of the SUGS Contribution on April 30, 2013, Regency entered into an agreement with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.
NGL Pipeline Regulation
We have interests in NGL pipelines located in Texas and New Mexico. We commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the Interstate Commerce Act (“ICA”) and the Energy Policy Act of 1992. Under the ICA, tariff rates must be just and reasonable and not unduly discriminatory and pipelines may not confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC’s rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.
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. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Rental expense[(1)]	$25	$30	$56	$62
Less: Sublease rental income	(10)	(5)	(18)	(10)
Rental expense, net	$15	$25	$38	$52

(1) Includes contingent rentals totaling $6 million for the three months ended June 30, 2014 and 2013, and $9 million and $10 million for the six months ended June 30, 2014 and 2013, respectively.

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates’ capital requirements, such as for funding capital projects or repayment of long-term obligations.
Litigation and Contingencies
We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

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MTBE Litigation

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

As of June 30, 2014, Sunoco is a defendant in nine cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Six of these cases are venued in a multidistrict litigation ("MDL") proceeding in a New York federal court. The most recently filed Puerto Rico action is expected to be transferred to the MDL. The New Jersey, Puerto Rico, Vermont, and Pennsylvania cases assert natural resource damage claims.

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

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of June 30, 2014 and December 31, 2013, accruals of approximately $43 million and $46 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

No amounts have been recorded in our June 30, 2014 or December 31, 2013 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

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

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applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Panhandle (as successor to Southern Union) believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Panhandle will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Environmental Matters

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

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

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

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Currently operating Sunoco 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, 2014, Sunoco had been named as a PRP at approximately 40 identified or potentially identifiable “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.

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

	June 30, 2014	December 31, 2013
Current	$71	$45
Non-current	319	350
Total environmental liabilities	$390	$395

In 2013, we established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the three months ended June 30, 2014 and 2013, Sunoco recorded $9 million and $8 million, respectively, of expenditures related to environmental cleanup programs. During the six months ended June 30, 2014 and 2013, Sunoco recorded $17 million and $15 million, respectively, of expenditures related to environmental cleanup programs.

On June 29, 2011, the U.S. Environmental Protection Agency finalized a rule under the Clean Air Act that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule’s requirements, because the rule applies only to changes we might make in the future.

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

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

14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts

consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.
We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related

financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

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

We may use derivatives in our NGL transportation and services segment to manage our storage facilities and the purchase and sale of purity NGLs.

Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are able and willing to bear it. Since the first quarter 2013, Sunoco Logistics has not designated any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment’s operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading and marketing activities related to power and natural gas in our all other segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

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The following table details our outstanding commodity-related derivatives:

	June 30, 2014		December 31, 2013	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	—	—	9,457,500	2014-2019
Basis Swaps IFERC/NYMEX[(1)]	16,632,500	2014-2015	(487,500)	2014-2017
Swing Swaps	—	—	1,937,500	2014-2016
Power (Megawatt):				
Forwards	270,150	2014	351,050	2014
Futures	10,670	2014	(772,476)	2014
Options – Puts	(54,400)	2014	(52,800)	2014
Options – Calls	54,400	2014	103,200	2014
Crude (Bbls) – Futures	(40,000)	2014	103,000	2014
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(2,537,500)	2014-2015	570,000	2014
Swing Swaps IFERC	26,147,500	2014-2015	(9,690,000)	2014-2016
Fixed Swaps/Futures	(4,445,000)	2014-2019	(8,195,000)	2014-2015
Forward Physical Contracts	(5,908,374)	2014-2015	5,668,559	2014-2015
Natural Gas Liquid (Bbls) – Forwards/Swaps	(1,823,200)	2014-2015	(1,133,600)	2014
Refined Products (Bbls) – Futures	(1,605,000)	2014-2015	(280,000)	2014
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	—	—	(7,352,500)	2014
Fixed Swaps/Futures	(1,757,500)	2014	(50,530,000)	2014
Hedged Item – Inventory	1,757,500	2014	50,530,000	2014
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(920,000)	2014	(1,825,000)	2014
Fixed Swaps/Futures	(6,440,000)	2014	(12,775,000)	2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	(510,000)	2014	(780,000)	2014
Crude (Bbls) – Futures	—	—	(30,000)	2014

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

We expect losses of $3 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, 2014	Notional Amount Outstanding December 31, 2013
ETP	July 2014(2)	Forward-starting to pay a fixed rate of 4.15% and receive a floating rate	$300	$400
ETP	July 2015(2)	Forward-starting to pay a fixed rate of 3.38% and receive a floating rate	200	—
ETP	July 2016(3)	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	—
ETP	July 2017(4)	Forward-starting to pay a fixed rate of 4.18% and receive a floating rate	200	—
ETP	July 2018(4)	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	—	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	—	400
ETP	February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	200	400
Panhandle	November 2021	Pay a fixed rate of 3.80% and receive a floating rate	275	275

(1) Floating rates are based on 3-month LIBOR.
(2) Represents the effective date. These forward-starting swaps have terms of 10 years with a mandatory termination date the same as the effective date.
(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.
(4) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership’s portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.
The Partnership’s counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

We have maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established

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

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$1	$3	$(4)	$(18)
	1	3	(4)	(18)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	59	227	(73)	(209)
Commodity derivatives	47	39	(44)	(38)
Interest rate derivatives	3	47	(121)	(95)
	109	313	(238)	(342)
Total derivatives	$110	$316	$(242)	$(360)

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

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$47	$41	$(44)	$(38)
Broker cleared derivative contracts	Other current assets	106	265	(150)	(318)
		153	306	(194)	(356)
Offsetting agreements:					
Counterparty netting	Price risk management assets (liabilities)	(38)	(36)	38	36
Payments on margin deposit	Other current assets	(8)	(1)	35	55
		(46)	(37)	73	91
Net derivatives with offsetting agreements		107	269	(121)	(265)
Derivatives without offsetting agreements		3	47	(121)	(95)
Total derivatives		$110	$316	$(242)	$(360)

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,	
	2014	2013	2014	2013
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$(2)	$6	$(6)	$8
Total	$(2)	$6	$(6)	$8

	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,	
		2014	2013	2014	2013
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$(2)	$1	$(6)	$2
Total		$(2)	$1	$(6)	$2

	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,	
		2014	2013	2014	2013
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$—	$(1)	$(6)	$4
Total		$—	$(1)	$(6)	$4

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	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,	
		2014	2013	2014	2013
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$(5)	$3	$2	$(1)
Commodity derivatives – Non-trading	Cost of products sold	(32)	21	(25)	3
Commodity derivatives – Non-trading	Deferred gas purchases	—	2	—	(3)
Interest rate derivatives	Gains (losses) on interest rate derivatives	(46)	39	(48)	46
Total		$(83)	$65	$(71)	$45

15. RELATED PARTY TRANSACTIONS:

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

In connection with the Trunkline LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG's regasification facility and the development of a liquefaction project at Trunkline LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015.

The Partnership also has related party transactions with several of its equity method investees. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Affiliated revenues	$390	$333	$731	$715

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

	June 30, 2014	December 31, 2013
Accounts receivable from related companies:		
ETE	$64	$18
Regency	62	53
PES	6	7
FGT	14	29
ET Crude Oil	24	24
Trunkline LNG	30	—
Other	55	34
Total accounts receivable from related companies:	$255	$165
Accounts payable to related companies:		
ETE	$3	$8
Regency	55	24
PES	16	—
FGT	2	8
Trunkline LNG	10	—
Other	2	5
Total accounts payable to related companies:	$88	$45

16. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	June 30, 2014	December 31, 2013
Deposits paid to vendors	$40	$49
Prepaid and other	226	261
Total other current assets	$266	$310

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Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2014	December 31, 2013
Interest payable	$296	$294
Customer advances and deposits	84	126
Accrued capital expenditures	291	166
Accrued wages and benefits	107	155
Taxes payable other than income taxes	295	214
Income taxes payable	219	3
Deferred income taxes	152	119
Other	238	351
Total accrued and other current liabilities	$1,682	$1,428

17. REPORTABLE SEGMENTS:

Our financial statements currently reflect the following reportable segments, which conduct their business in the United States, as follows:

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

During the fourth quarter 2013, management realigned the composition of our reportable segments, and as a result, our natural gas marketing operations are now aggregated into the "all other" segment. These operations were previously reported in the midstream segment. Based on this change in our segment presentation, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

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

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

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership.

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The following tables present financial information by segment:

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$669	$558	$1,516	$1,203
Intersegment revenues	43	65	130	104
	712	623	1,646	1,307
Interstate transportation and storage:				
Revenues from external customers	245	354	540	677
Intersegment revenues	4	3	7	4
	249	357	547	681
Midstream:				
Revenues from external customers	302	308	604	639
Intersegment revenues	418	269	769	538
	720	577	1,373	1,177
NGL transportation and services:				
Revenues from external customers	878	420	1,679	766
Intersegment revenues	25	18	54	37
	903	438	1,733	803
Investment in Sunoco Logistics:				
Revenues from external customers	4,766	4,256	9,218	7,713
Intersegment revenues	55	55	80	110
	4,821	4,311	9,298	7,823
Retail marketing:				
Revenues from external customers	5,568	5,291	10,576	10,508
Intersegment revenues	—	—	3	5
	5,568	5,291	10,579	10,513
All other:				
Revenues from external customers	601	364	1,128	899
Intersegment revenues	120	121	184	217
	721	485	1,312	1,116
Eliminations	(665)	(531)	(1,227)	(1,015)
Total revenues	$13,029	$11,551	$25,261	$22,405

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	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$110	$112	$287	$244
Interstate transportation and storage	265	361	565	658
Midstream	157	127	283	214
NGL transportation and services	141	77	269	157
Investment in Sunoco Logistics	280	244	488	480
Retail marketing	136	97	245	134
All other	80	51	238	138
Total	1,169	1,069	2,375	2,025
Depreciation and amortization	(268)	(251)	(534)	(511)
Interest expense, net of interest capitalized	(217)	(211)	(436)	(422)
Gain on sale of AmeriGas common units	93	—	163	—
Gains (losses) on interest rate derivatives	(46)	39	(48)	46
Non-cash unit-based compensation expense	(13)	(10)	(27)	(24)
Unrealized gains (losses) on commodity risk management activities	(1)	18	(30)	37
LIFO valuation adjustments	20	(22)	34	16
Adjusted EBITDA related to discontinued operations	—	(23)	(27)	(63)
Adjusted EBITDA related to unconsolidated affiliates	(170)	(158)	(366)	(323)
Equity in earnings of unconsolidated affiliates	57	37	136	109
Other, net	(15)	5	(18)	8
Income from continuing operations before income tax expense	$609	$493	$1,222	$898

	June 30, 2014	December 31, 2013
Total assets:		
Intrastate transportation and storage	$4,504	$4,606
Interstate transportation and storage	10,158	10,988
Midstream	3,307	3,133
NGL transportation and services	4,576	4,326
Investment in Sunoco Logistics	13,437	11,650
Retail marketing	4,532	3,936
All other	3,709	5,063
Total	$44,223	$43,702

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

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; (ii) our Annual Report on Form 10-K for the year ended December 31, 2013 filed with the SEC on February 27, 2014; and (iii) our management's discussion and analysis of financial condition and results of operations included in our 2013 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, 2013.

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

OVERVIEW

The primary activities and operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Panhandle is the parent company of the 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 and MACS.

RECENT DEVELOPMENTS

Susser Holdings Merger

On April 27, 2014, ETP entered into a definitive merger agreement whereby ETP plans to acquire Susser Holdings Corporation ("Susser Holdings") in a unit and cash transaction for total consideration valued at approximately $1.8 billion (the "Susser Merger"). By acquiring Susser Holdings, ETP will own the general partner interest and the incentive distribution rights in Susser Petroleum Partners LP ("Susser Petroleum"), approximately 11 million Susser Petroleum common units (representing approximately 50.2% of Susser Petroleum's outstanding units), and Susser Holdings' existing retail operations, consisting of 630 convenience store locations. The Susser Merger is expected to close in the third quarter of 2014, subject to approval of the shareholders of Susser Holdings.

Sale of AmeriGas Common Units

In January 2014, June 2014 and August 2014, we sold 9.2 million, 8.5 million and 1.2 million AmeriGas common units, respectively, for net proceeds of $381 million, $377 million and $55 million, respectively. Net proceeds from these sales were used to repay borrowings under the ETP Credit Facility and for general partnership purposes. Subsequent to the August 2014 sale, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Pipeline Construction Projects

In June 2014, ETP announced that our Board of Directors approved the construction of an approximately 1,100 mile pipeline to transport crude oil supply from strategic receipt points in the Bakken/Three Forks production area in North Dakota to Patoka, Illinois, where the pipeline will interconnect with ETP's existing Trunkline Pipeline, which is being converted from natural gas service to crude oil transportation service. ETP currently expects to build the pipeline to a capacity as high as 570,000 Bbls/d based on binding commitments received to date and ongoing discussions with a number of key potential shippers. The pipeline is expected to be in service by the end of 2016 with an estimated cost of approximately $4.8 billion to $5.0 billion. It is expected that ETE and ETP will initially own 60% and 40%, respectively, of the pipeline project and that, based on discussions with potential third party shippers on the pipeline regarding equity interests of up to 49% in the pipeline project, the ultimate ownership interests

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of ETE and ETP in the project may be reduced. In any event, it is expected that ETP or Sunoco Logistics will be the construction manager during construction of the pipeline project and will be the operator of the pipeline following the completion of construction.

In June 2014, ETP also announced that our Board of Directors approved the construction of an approximately 820 mile pipeline (“ET Rover”) to transport natural gas from the prolific Marcellus and Utica Shale areas to numerous market regions in the United States and Canada. To date, ETP has secured 2.95 Bcf/d of binding, fee-based commitments under predominantly 20 year agreements, representing 91% of the 3.25 Bcf/d total design capacity, and is still evaluating additional bids that were received in the open season. The project is fully subscribed to the Dawn, Ontario hub at 1.3 Bcf/d, with the balance of capacity commitments delivered to interconnects with other pipelines in the Midwest. The project cost is estimated to be $3.8 billion to $4.4 billion and is expected to be in service to Defiance, Ohio by December 2016 and to Dawn, Ontario by July 2017. ETP has granted options to third party shippers to acquire up to 49% of the equity interests in the pipeline project. ETP will be the construction manager for the pipeline project and the operator of the pipeline following completion of construction.

Quarterly Cash Distribution Increase

In July 2014, ETP announced that its Board of Directors approved an increase in its quarterly distribution to $0.955 per unit ($3.82 annualized) on ETP Common Units for the quarter ended June 30, 2014, representing an increase of $0.08 per Common Unit on an annualized basis compared to the first quarter of 2014.

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Results of Operations
Consolidated Results

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Change	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$110	$112	$(2)	$287	$244	$43
Interstate transportation and storage	265	361	(96)	565	658	(93)
Midstream	157	127	30	283	214	69
NGL transportation and services	141	77	64	269	157	112
Investment in Sunoco Logistics	280	244	36	488	480	8
Retail marketing	136	97	39	245	134	111
All other	80	51	29	238	138	100
Total	1,169	1,069	100	2,375	2,025	350
Depreciation and amortization	(268)	(251)	(17)	(534)	(511)	(23)
Interest expense, net of interest capitalized	(217)	(211)	(6)	(436)	(422)	(14)
Gain on sale of AmeriGas common units	93	—	93	163	—	163
Gains (losses) on interest rate derivatives	(46)	39	(85)	(48)	46	(94)
Non-cash unit-based compensation expense	(13)	(10)	(3)	(27)	(24)	(3)
Unrealized gains (losses) on commodity risk management activities	(1)	18	(19)	(30)	37	(67)
LIFO valuation adjustments	20	(22)	42	34	16	18
Adjusted EBITDA related to discontinued operations	—	(23)	23	(27)	(63)	36
Adjusted EBITDA related to unconsolidated affiliates	(170)	(158)	(12)	(366)	(323)	(43)
Equity in earnings of unconsolidated affiliates	57	37	20	136	109	27
Other, net	(15)	5	(20)	(18)	8	(26)
Income from continuing operations before income tax expense	609	493	116	1,222	898	324
Income tax expense from continuing operations	(70)	(89)	19	(216)	(92)	(124)
Income from continuing operations	539	404	135	1,006	806	200
Income from discontinued operations	42	9	33	66	31	35
Net income	$581	$413	$168	$1,072	$837	$235

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization expense increased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to additional depreciation from assets recently

placed in service.
Gain on Sale of AmeriGas Common Units. In January 2014 and June 2014, the Partnership recognized a gain on the sale of 9.2 million and 8.5 million AmeriGas common units, respectively, that were originally received in connection with the contribution of our propane business to AmeriGas in 2012. As of June 30, 2014, the Partnership held 4.4 million AmeriGas common units.
Gains (Losses) on Interest Rate Derivatives. Losses on interest rate derivatives during the three and six months ended June 30, 2014 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value. Conversely,

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increases in forward interest rates resulted in gains on interest rate derivatives during the three and six months ended June 30, 2013.

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

LIFO Valuation Adjustments. LIFO valuation reserve adjustments were recorded during the three and six months ended June 30, 2014 and 2013, respectively, for the inventory associated with Sunoco’s retail marketing operations as a result of commodity price changes between periods.

Adjusted EBITDA Related to Discontinued Operations. Amounts for the six months ended June 30, 2014 related to a marketing business that was sold effective April 1, 2014. Amounts for the three and six months ended June 30, 2013 related to Southern Union’s local distribution operations.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. See additional information in “Supplemental Information on Unconsolidated Affiliates” and “Segment Operating Results” below.

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

Income Tax Expense from Continuing Operations. Income tax expense is based on the earnings of our taxable subsidiaries. In addition, the six months ended June 30, 2014 included the impact of the Trunkline LNG Transaction, which was treated as a sale for tax purposes, resulting in $87 million of incremental income tax expense.

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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,		
	2014	2013	Change	2014	2013	Change
Equity in earnings (losses) of unconsolidated affiliates:						
AmeriGas	$(8)	$(20)	$12	$26	$43	$(17)
Citrus	26	24	2	44	38	6
FEP	13	14	(1)	27	27	—
Regency	1	2	(1)	(6)	2	(8)
PES	18	13	5	35	(9)	44
Other	7	4	3	10	8	2
Total equity in earnings of unconsolidated affiliates	$57	$37	$20	$136	$109	$27
Proportionate share of interest, depreciation, amortization, non-cash items and taxes:						
AmeriGas	$13	$36	$(23)	$30	$70	$(40)
Citrus	55	55	—	105	103	2
FEP	5	5	—	10	10	—
Regency	24	14	10	58	14	44
PES	7	5	2	13	6	7
Other	9	6	3	14	11	3
Total proportionate share of interest, depreciation, amortization, non-cash items and taxes	$113	$121	$(8)	$230	$214	$16
Adjusted EBITDA related to unconsolidated affiliates:						
AmeriGas	$5	$16	$(11)	$56	$113	$(57)
Citrus	81	79	2	149	141	8
FEP	18	19	(1)	37	37	—
Regency	25	16	9	52	16	36
PES	25	18	7	48	(3)	51
Other	16	10	6	24	19	5
Total Adjusted EBITDA related to unconsolidated affiliates	$170	$158	$12	$366	$323	$43
Distributions received from unconsolidated affiliates:						
AmeriGas	$11	$24	$(13)	$22	$48	$(26)
Citrus	41	39	2	75	63	12
FEP	16	16	—	32	33	(1)
Regency	15	15	—	30	15	15
PES	—	—	—	—	25	(25)
Other	9	8	1	14	13	1

Total distributions received from unconsolidated affiliates	$92	$102	$(10)	$173	$197	$(24)

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Segment Operating Results

Our reportable segments are discussed below. "All other" includes our compression operations, our investment in AmeriGas, Southern Union's local distribution operations, our approximate 33% non-operating interest in PES, our investment in Regency and our natural gas marketing operations.

For the three and six months ended June 30, 2013, certain costs previously reported as selling, general and administrative expenses were reclassified to operating expenses to conform to the current year presentation. These costs include support functions such as engineering, environmental services, maintenance and reliability, pipeline integrity, procurement and technical services.

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

The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

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

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for the year ended December 31, 2013 filed with the SEC on February 27, 2014.

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Natural gas transported (MMBtu/d)	9,069,215	9,654,524	(585,309)	9,299,177	9,682,789	(383,612)
Revenues	$712	$623	$89	$1,646	$1,307	$339
Cost of products sold	551	447	104	1,285	937	348
Gross margin	161	176	(15)	361	370	(9)
Unrealized (gains) losses on commodity risk management activities	(3)	(12)	9	24	(24)	48
Operating expenses, excluding non-cash compensation expense	(43)	(47)	4	(85)	(89)	4
Selling, general and administrative expenses, excluding non-cash compensation expense	(5)	(5)	—	(12)	(13)	1
Adjusted EBITDA related to unconsolidated affiliates	—	—	—	(1)	—	(1)
Segment Adjusted EBITDA	$110	$112	$(2)	$287	$244	$43

Volumes. Transported volumes decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to the reduction of volumes under certain long-term transportation contracts offset by increased volumes due to a more favorable pricing 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,		
	2014	2013	Change	2014	2013	Change
Transportation fees	$114	$124	$(10)	$231	$253	$(22)
Natural gas sales and other	17	19	(2)	58	46	12
Retained fuel revenues	26	26	—	56	49	7
Storage margin, including fees	4	7	(3)	16	22	(6)
Total gross margin	$161	$176	$(15)	$361	$370	$(9)

Intrastate transportation and storage gross margin decreased for the three months ended June 30, 2014 compared to the same period last year due to the following:

- Transportation fees. Transportation fees decreased primarily due to the reduction of volumes under certain long-term transportation contracts.
- Natural gas sales and other. Margin from natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, gains and losses on derivatives used to hedge net retained fuel, and the margin from gas sales, processing and gathering fees on our Houston pipeline system. Margin from natural gas sales and other decreased primarily due to operational gas loss in the current period.

For the six months ended June 30, 2014 compared to the same period last year, intrastate transportation and storage gross margin decreased due to the following:

- Transportation fees. Transportation fees decreased primarily due to the reduction of volumes under certain long-term transportation contracts.
- Natural gas sales and other. Margin from natural gas sales and other increased primarily due to opportunities from the commodity price volatility created by the cold winter season during the first quarter of 2014.
- Retained fuel revenues. Retention revenue increased primarily due to higher average natural gas spot prices. The average spot price at the Houston Ship Channel location for the six months ended June 30, 2014 was $4.81/MMBtu, an increase of $1.09/MMBtu compared to the same period last year.

Storage margin was comprised of the following:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Withdrawals from storage natural gas inventory (MMBtu)	—	—	—	37,806,832	11,953,718	25,853,114
Realized margin on natural gas inventory transactions	$(6)	$(11)	$5	$28	$(14)	$42
Fair value inventory adjustments	—	(15)	15	(11)	5	(16)
Unrealized gains (losses) on derivatives	4	26	(22)	(14)	17	(31)
Margin recognized on natural gas inventory, including related derivatives	(2)	—	(2)	3	8	(5)
Revenues from fee-based storage	6	7	(1)	13	14	(1)
Total storage margin	$4	$7	$(3)	$16	$22	$(6)

For the three and six months ended June 30, 2014 compared to the same periods last year, the decreases in storage margin were principally driven by a less favorable storage environment leading to a decline in the spreads between the spot and forward prices on natural gas we own in the Bammel storage facility.

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Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized gains and losses on commodity risk management activities reflect the net impact from storage and non-storage derivatives, as well as fair value adjustments to inventory. We experienced decreases of $9 million and $48 million, respectively, in the margin from unrealized gains and losses on commodity risk management activities for the three and six months ended June 30, 2014 compared to the same periods last year.

For the three months ended June 30, 2014, unrealized gains from commodity risk management activities of $3 million consisted of losses from storage and non-storage related derivatives. For the three months ended June 30, 2013, unrealized gains of $12 million included unrealized gains on storage and non-storage related derivatives of $26 million, offset by losses from the fair value adjustments to storage gas inventory of $15 million.

For the six months ended June 30, 2014, unrealized losses on commodity risk management activities of $24 million included $13 million of losses from storage and non-storage related derivatives, as well as $11 million in losses from mark-to-market of physical storage gas during the period. Unrealized losses from storage related activities were offset by realized margin on natural gas inventory transactions as illustrated in the storage margin table above. For the six months ended June 30, 2013, unrealized gains of $24 million included unrealized gains on storage and non-storage related derivatives of $19 million and fair value adjustments to physical storage gas of $5 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to decreases in ad valorem taxes driven by the settlement of lower valuations with local taxing authorities during the current period.

Interstate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Natural gas transported (MMBtu/d)	5,594,099	6,204,788	(610,689)	6,449,834	6,617,005	(167,171)
Natural gas sold (MMBtu/d)	15,733	16,795	(1,062)	15,758	16,782	(1,024)
Revenues	$249	$357	$(108)	$547	$681	$(134)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(67)	(75)	8	(138)	(153)	15
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(16)	(19)	3	(30)	(48)	18
Adjusted EBITDA related to unconsolidated affiliates	99	98	1	186	178	8
Segment Adjusted EBITDA	$265	$361	$(96)	$565	$658	$(93)

Volumes. For the three months ended June 30, 2014 compared to the same period last year, transported volumes decreased due to declines in supply on the Tiger pipeline, lower contracted capacity on the Trunkline pipeline, and lower contract utilization on the Transwestern pipeline.

For the six months ended June 30, 2014 compared to the same period last year, transported volumes decreased due to declines in supply on the Tiger pipeline, lower volumes on the Transwestern pipeline due to a customer outage and lower contract utilization, and lower volumes on the Sea Robin pipeline due to a system outage and declines in production. These decreases were partially offset by higher volumes transported on the Panhandle and Trunkline pipelines due to increased demand resulting from the cold winter season during the first quarter of 2014.

Revenues. The decreases in volumes transported, as discussed above, did not significantly impact revenues, which are primarily fixed fees for the reservation of capacity on the pipelines. Interstate transportation and storage revenues decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to the deconsolidation of Trunkline LNG effective January 1, 2014 and the recognition in the second quarter of 2013 of $52 million received in connection with the buyout of a customer contract. Revenues for Trunkline LNG for the three and six months ended June 30, 2013 were $54 million and $107 million, respectively. For the six months ended June 30, 2014, these decreases were partially offset by favorable impacts from the cold winter season during the first quarter of 2014.

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Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage operating expenses decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to the deconsolidation of Trunkline LNG effective January 1, 2014.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage selling, general and administrative expenses decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to decreases of $2 million and $6 million, respectively, in professional fees and decreases of $1 million and $5 million, respectively, due to the deconsolidation of Trunkline LNG effective January 1, 2014. For the six months ended June 30, 2014 decreased employee-related costs of $7 million were realized primarily through the successful integration of Southern Union's transportation and storage operations.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to increased earnings from Citrus as a result of the sale of additional capacity and lower operating expenses due to lower ad valorem taxes.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Gathered volumes (MMBtu/d):						
ETP legacy assets	2,851,414	2,531,076	320,338	2,705,941	2,433,627	272,314
Southern Union gathering and processing(1)	—	529,327	(529,327)	—	492,586	(492,586)
NGLs produced (Bbls/d):						
ETP legacy assets	163,780	112,951	50,829	150,373	104,927	45,446
Southern Union gathering and processing(1)	—	43,777	(43,777)	—	40,705	(40,705)
Equity NGLs produced (Bbls/d):						
ETP legacy assets	14,968	14,854	114	13,545	12,299	1,246
Southern Union gathering and processing(1)	—	8,216	(8,216)	—	7,459	(7,459)
Revenues	$720	$577	$143	$1,373	$1,177	$196
Cost of products sold	530	402	128	1,023	839	184
Gross margin	190	175	15	350	338	12
Unrealized gains on commodity risk management activities	—	(2)	2	—	(2)	2
Operating expenses, excluding non-cash compensation expense	(29)	(41)	12	(57)	(98)	41
Selling, general and administrative expenses, excluding non-cash compensation expense	(4)	(5)	1	(10)	(24)	14
Segment Adjusted EBITDA	$157	$127	$30	$283	$214	$69

(1) Southern Union contributed its gathering and processing operations to Regency, resulting in the deconsolidation of those operations on April 30, 2013.

Volumes. For the ETP legacy assets, the increases in gathered volumes, NGLs produced and equity NGLs produced during the three and six months ended June 30, 2014 compared to the same periods last year were primarily due to increased production by our customers in the Eagle Ford Shale and a 400 MMcf/d increase in processing capacity. Volumes from Southern Union's gathering and processing operations reflected the deconsolidation of those operations on April 30, 2013.

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

	Three Months Ended June 30, 2014	2013	Change	Six Months Ended June 30, 2014	2013	Change
Gathering and processing fee-based revenues	$134	$114	$20	$257	$211	$46
Non fee-based contracts and processing	59	64	(5)	96	131	(35)
Other	(3)	(3)	—	(3)	(4)	1
Total gross margin	$190	$175	$15	$350	$338	$12

Midstream gross margin increased for the three months ended June 30, 2014 compared to the same period last year due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale resulted in increased fee-based revenues of $21 million. This increase was partially offset by a decrease of $2 million due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.
- Non fee-based contracts and processing. Non fee-based gross margin decreased $13 million primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013. Excluding the impact of the deconsolidation, non fee-based margin on the ETP legacy assets increased by $8 million primarily due to operational efficiencies and a slightly better commodity price environment.

For the six months ended June 30, 2014 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 and increased capacity from assets recently placed in service in the Eagle Ford Shale resulted in increased fee-based revenues of $54 million. This increase was partially offset by a decrease of $8 million due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.
- Non fee-based contracts and processing. Non fee-based gross margins decreased $40 million primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013. Excluding the impact of the deconsolidation, non fee-based margin increased primarily due to higher equity NGL volumes on the Eagle Ford system.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to the deconsolidation of Southern Union's gathering and processing operations on April 30, 2013.

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NGL Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
NGL transportation volumes (Bbls/d)	367,564	274,022	93,542	337,456	250,830	86,626
NGL fractionation volumes (Bbls/d)	191,255	98,915	92,340	174,171	92,843	81,328
Revenues	$903	$438	$465	$1,733	$803	$930
Cost of products sold	731	329	402	1,402	586	816
Gross margin	172	109	63	331	217	114
Unrealized (gains) losses on commodity risk management activities	—	(2)	2	1	(2)	3
Operating expenses, excluding non-cash compensation expense	(29)	(28)	(1)	(57)	(50)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(4)	(3)	(1)	(9)	(10)	1
Adjusted EBITDA related to unconsolidated affiliates	2	1	1	3	2	1
Segment Adjusted EBITDA	$141	$77	$64	$269	$157	$112

Volumes. The increase in NGL transportation volumes for the three and six months ended June 30, 2014 compared to the same periods last year reflected increases of approximately 55,600 Bbls/d and 47,700 Bbls/d, respectively, in volumes transported out of west Texas and the Eagle Ford Shale on our Lone Star pipeline system. The remainder of the increase in volumes transported was primarily due to increases in NGL production from our Jackson processing plant and volumes destined for Mont Belvieu, Texas via our Justice pipeline. Average daily fractionated volumes increased for the three and six months ended June 30, 2014 compared to the same periods last year due to the recent commissioning of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas in October 2013. 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,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Transportation margin	$69	$45	$24	$128	$86	$42
Processing and fractionation margin	57	30	27	106	64	42
Storage margin	37	34	3	77	66	11
Other margin	9	—	9	20	1	19
Total gross margin	$172	$109	$63	$331	$217	$114

NGL transportation and services gross margin increased for the three and six months ended June 30, 2014 compared to the same periods last year due to the following:

- Transportation margin. For the three and six months ended June 30, 2014, transportation margin increased $14 million and $22 million, respectively, due to an increase in volumes transported from West Texas and the Eagle Ford Shale on our Lone Star pipeline system. The remainder of the increases in transportation margin between periods were due to increases in NGL production from our processing plants that connect to various fractionators via our wholly-owned pipelines.
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Processing and fractionation margin. For the three and six months ended June 30, 2014, processing and fractionation margin increased $31 million and $54 million, respectively, due to the startup of Lone Star's second fractionator at Mont Belvieu, Texas in October 2013. These increases in margin related to our fractionators in Mont Belvieu, Texas were partially offset by decreases of $3 million and $11 million, respectively, in margin attributable to our fractionator in Geismar, Louisiana due to lower overall production volumes through the facility following the expiration of a major supplier contract in June 2013.

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- Storage margin. For the three and six months ended June 30, 2014, storage margin increased approximately $3 million and $10 million, respectively, from blending operations and other non fee-based storage activities. For the six months ended June 30, 2014, storage margin also reflected an increase in contracted storage fees of $1 million.
- Other margin. The increases in other margin for the three and six months ended June 30, 2014 compared to the same periods last year resulted from increased commercial optimization activities related to our fractionators, primarily due to the recent commissioning of our second fractionator at Mont Belvieu and the optimization of available storage capacity at our Mont Belvieu, Texas facility.

Operating Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services operating expenses increased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to the startup of Lone Star's second fractionator in Mont Belvieu, Texas in October 2013. The increases in operating expenses for the three and six months ended June 30, 2014 compared to the same periods last year were partially offset by decreases in ad valorem taxes of $3 million and $4 million, respectively, driven by the settlement of lower valuations with local taxing authorities during the current period.

Investment in Sunoco Logistics

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Revenues	$4,821	$4,311	$510	$9,298	$7,823	$1,475
Cost of products sold	4,517	4,023	494	8,727	7,247	1,480
Gross margin	304	288	16	571	576	(5)
Unrealized (gains) losses on commodity risk management activities	8	(1)	9	7	(4)	11
Operating expenses, excluding non-cash compensation expense	(21)	(25)	4	(53)	(51)	(2)
Selling, general and administrative expenses, excluding non-cash compensation expense	(25)	(29)	4	(59)	(59)	—
Adjusted EBITDA related to unconsolidated affiliates	14	11	3	22	18	4
Segment Adjusted EBITDA	$280	$244	$36	$488	$480	$8

Segment Adjusted EBITDA. For the three months ended June 30, 2014 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- An increase of $16 million from crude oil pipelines, primarily due to higher throughput;
- An increase of $27 million from terminal facilities, primarily due to higher volumes and increased margins from refined products acquisition and marketing activities; and
- An increase of $10 million from refined products pipelines, primarily due to operating results from Sunoco Logistics' Mariner West project; partially offset by
- A decrease of $17 million from crude oil acquisition and marketing activities, primarily due to lower crude margins, the impact from which was partially offset by $5 million from increased crude volumes resulting from higher market demand and expansion in the crude oil trucking fleet.

For the six months ended June 30, 2014 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- An increase of $48 million from crude oil pipelines, primarily due to higher throughput;
- An increase of $59 million from terminal facilities, primarily due to higher volumes and increased margins from refined products acquisition and marketing activities; and
- An increase of $18 million from refined products pipelines, primarily due to operating results from Sunoco Logistics' Mariner West project; partially offset by

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- A decrease of $117 million from crude oil acquisition and marketing activities, primarily due to lower crude margins driven by contracted crude differentials, the impact from which was partially offset by $18 million from increased crude volumes resulting from higher market demand and expansion in the crude oil trucking fleet.

Retail Marketing

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Total retail gasoline outlets, end of period	5,152	4,974	178	5,152	4,974	178
Total company-operated outlets, end of period	568	440	128	568	440	128
Gasoline and diesel throughput per company-operated site (gallons/month)	197,824	204,320	(6,496)	188,404	195,710	(7,306)
Revenues	$5,568	$5,291	$277	$10,579	$10,513	$66
Cost of products sold	5,260	5,087	173	10,016	10,123	(107)
Gross margin	308	204	104	563	390	173
Unrealized (gains) losses on commodity risk management activities	(1)	—	(1)	2	—	2
Operating expenses, excluding non-cash compensation expense	(124)	(106)	(18)	(240)	(204)	(36)
Selling, general and administrative expenses, excluding non-cash compensation expense	(28)	(23)	(5)	(48)	(38)	(10)
LIFO valuation adjustments	(20)	22	(42)	(34)	(16)	(18)
Adjusted EBITDA related to unconsolidated affiliates	1	1	—	2	3	(1)
Other	—	(1)	1	—	(1)	1
Segment Adjusted EBITDA	$136	$97	$39	$245	$134	$111

Gross Margin. For the three months ended June 30, 2014 compared to the same period last year, retail marketing gross margin included a favorable impact of $42 million from non-cash LIFO valuation adjustments and $17 million from increased fuel margins. The remainder of the increase was primarily attributable to recent acquisitions.

For the six months ended June 30, 2014 compared to the same period last year, stronger retail gasoline and distillate margins had a favorable impact of $41 million, recent acquisitions resulted in an increase of $70 million and non-cash LIFO valuation adjustments also resulted in an increase of $18 million. The remainder of the increase was primarily attributable to favorable non-retail fuel margins.

Operating Expenses, Excluding Non-Cash Compensation Expense. Retail marketing operating expenses increased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to recent acquisitions.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Retail marketing selling, general and administrative expenses increased for the three and six months ended June 30, 2014 compared to the same periods last year primarily due to recent acquisitions.

LIFO Valuation Adjustments. Retail marketing recorded LIFO valuation reserve adjustments as a result of commodity price changes between periods.

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All Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Revenues	$721	$485	$236	$1,312	$1,116	$196
Cost of products sold	710	466	244	1,274	1,091	183
Gross margin	11	19	(8)	38	25	13
Unrealized gains on commodity risk management activities	(3)	(1)	(2)	(4)	(5)	1
Operating expenses, excluding non-cash compensation expense	3	(5)	8	(2)	(11)	9
Selling, general and administrative expenses, excluding non-cash compensation expense	(2)	(20)	18	(13)	(39)	26
Adjusted EBITDA related to discontinued operations	—	23	(23)	27	63	(36)
Adjusted EBITDA related to unconsolidated affiliates	55	49	6	157	125	32
Other	19	(11)	30	38	(11)	49
Elimination	(3)	(3)	—	(3)	(9)	6
Segment Adjusted EBITDA	$80	$51	$29	$238	$138	$100

Amounts reflected in our all other segment primarily include:

- our investment in AmeriGas;
- our natural gas compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture;
- 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; and
- our natural gas marketing operations.

For the three months ended June 30, 2014 compared to the same period last year, Segment Adjusted EBITDA increased due to the net impact of the following:

- an increase of $19 million in management fees, as further described below;
- a favorable impact of approximately $10 million due to costs associated with certain Sunoco activities that were included in the all other Segment Adjusted EBITDA in the prior year;
- favorable results from our commodity marketing business of $5 million;
- an increase of $6 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to higher earnings from our investments in PES and Regency, including the impact of only recording a partial period of earnings from Regency beginning on April 30, 2013, partially offset by a decrease of $11 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2013 and 2014;
- a refund of insurance premiums of $6 million included in the three months ended June 30, 2014;
- Southern Union corporate expenses of $3 million that were no longer included in the all other segment subsequent to the merger of Southern Union, PEPL Holdings and Panhandle in January 2014; offset by
- Adjusted EBITDA related to discontinued operations of $23 million in the prior period related to Southern Union’s local distribution operations that were sold in 2013.

For the six months ended June 30, 2014 compared to the same period last year, Segment Adjusted EBITDA increased due to the net impact of the following:

- an increase of $38 million in management fees, as further described below;

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- favorable results from our commodity marketing business of $28 million;
- a favorable impact of approximately $25 million due to costs associated with certain Sunoco activities that were included in the all other Segment Adjusted EBITDA in the prior year;
- an increase of $32 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to higher earnings from our investments in PES and Regency, including the impact of only recording a partial period of earnings from Regency beginning on April 30, 2013, partially offset by a decrease of $57 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2013 and 2014;
- a refund of insurance premiums of $6 million included in the six months ended June 30, 2014;
- Southern Union corporate expenses of $4 million that were no longer included in the all other segment subsequent to the merger of Southern Union, PEPL Holdings and Panhandle in January 2014; offset by
- a decrease in Adjusted EBITDA related to discontinued operations of $36 million primarily due to the sale of Southern Union's local distribution operations in 2013.

In connection with the Trunkline LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG's regasification facility and the development of a liquefaction project at Trunkline LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. These fees were reflected in "Other" in the "All other" segment and for the three and six months ended June 30, 2014 were reflected as an offset to operating expenses of $7 million and $13 million, respectively, and selling, general and administrative expenses of $12 million and $25 million, respectively, in the consolidated statements of operations.

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 (net of contributions in aid of construction costs) for the full year 2014 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$150	$160	$25	$30
Interstate transportation and storage	80	100	100	110
Midstream	600	650	10	15
NGL transportation and services(1)	360	380	20	25
Investment in Sunoco Logistics	1,900	2,100	65	75
Retail marketing	130	150	50	60
All other (including eliminations)	110	120	10	20
Total projected capital expenditures	$3,330	$3,660	$280	$335

(1) Includes 100% of Lone Star's capital expenditures. We expect to receive capital contributions from Regency related to its 30% interest in Lone Star of between $85 million and $110 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, delays from steel mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors in our anticipated growth capital expenditures for each year.

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

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 resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Six months ended June 30, 2014 compared to six months ended June 30, 2013. Cash provided by operating activities during 2014 was $1.57 billion compared to $1.16 billion for 2013 and net income was $1.07 billion and $837 million for 2014 and 2013, respectively. The difference between net income and cash provided by operating activities for the six months ended June 30, 2014 primarily consisted of net changes in operating assets and liabilities of $351 million, gain on the sales of AmeriGas common units of $163 million and non-cash items totaling $213 million.

The non-cash activity in 2014 and 2013 consisted primarily of depreciation and amortization of $534 million and $511 million, respectively, non-cash compensation expense of $27 million and $24 million, respectively, and equity in earnings of unconsolidated affiliates of $136 million and $109 million, respectively. Non-cash activity in 2014 also included deferred income taxes of $111 million and the gain on the sale of AmeriGas common units of $163 million.

Cash paid for interest, net of interest capitalized, was $471 million and $448 million for the six months ended June 30, 2014 and 2013, respectively.

Capitalized interest was $35 million and $21 million for the six months ended June 30, 2014 and 2013, respectively.

Investing Activities

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

Six months ended June 30, 2014 compared to six months ended June 30, 2013. Cash used in investing activities during 2014 was $1.01 billion compared to $1.93 billion for 2013. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2014 were $1.68 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2013 of $1.12 billion. Additional detail related to our capital expenditures is provided in the table below. During the six months ended June 30, 2014, we received proceeds of $759 million from sales of AmeriGas common units. In 2014, we paid $196 million in cash for acquisitions and 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.

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The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the six months ended June 30, 2014:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Intrastate transportation and storage	$67	$14	$81	$(25)	$56
Interstate transportation and storage	20	27	47	6	53
Midstream	297	9	306	(19)	287
NGL transportation and services(1)	175	8	183	35	218
Investment in Sunoco Logistics	1,092	31	1,123	(123)	1,000
Retail marketing	34	18	52	17	69
All other (including eliminations)	5	(9)	(4)	(4)	(8)
Total	$1,690	$98	$1,788	$(113)	$1,675

(1) Includes 100% of Lone Star's capital expenditures. We received $84 million in cash for capital contributions from Regency related to its 30% interest in Lone Star during the six months ended June 30, 2014.

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 recent increases in our distribution rate and increases in the number of Common Units outstanding.

Six months ended June 30, 2014 compared to six months ended June 30, 2013. Cash provided by financing activities during 2014 was $10 million compared to $985 million for 2013. In 2014 and 2013, we received net proceeds from Common Unit offerings of $484 million and $1.09 billion, respectively, and in 2014, Sunoco Logistics received $102 million in net proceeds from offerings of their common units. During 2014, we had a net increase in our debt level of $449 million compared to a net increase of $962 million for 2013. We incurred $9 million of debt issuance costs in 2014 compared to $19 million in 2013. We have paid distributions of $943 million to our partners in 2014 compared to $873 million in 2013. We have also paid distributions of $157 million to noncontrolling interests in 2014 compared to $247 million in 2013. In addition, we have received capital contributions of $84 million from Regency for its noncontrolling interest in Lone Star in 2014 compared to $72 million in 2013.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 2014	December 31, 2013
ETP Senior Notes	$10,890	$11,182
Transwestern Senior Notes	870	870
Panhandle Senior Notes	1,085	1,085
Sunoco Senior Notes	965	965
Sunoco Logistics Senior Notes	2,975	2,150
Revolving credit facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	—	65
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	35
Sunoco Logistics $1.5 billion Revolving Credit Facility due November 19, 2018	250	200
Other long-term debt	228	228
Unamortized premiums, net of discounts and fair value adjustments	268	308
Total debt	17,566	17,088
Less: Current maturities of long-term debt	1,346	637
Long-term debt, less current maturities	$16,220	$16,451

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, 2013, filed with the SEC on February 27, 2014 and in Note 8 to our consolidated interim financial statements.

Senior Notes

In April 2014, Sunoco Logistics issued $300 million aggregate principal amount of 4.25% Senior Notes due April 2024 and $700 million aggregate principal amount of 5.30% Senior Notes due April 2044. The net proceeds from the offering were used to pay outstanding borrowings under the Sunoco Logistics Credit Facility and for general partnership purposes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. As of June 30, 2014, the ETP Credit Facility had no outstanding borrowings.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $1.5 billion unsecured credit facility (the "Sunoco Logistics Credit Facility"), which matures in November 2018. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $2.25 billion under certain conditions. The credit facility is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The credit facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. As of June 30, 2014, the Sunoco Logistics Credit Facility had $250 million outstanding.

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, 2014.

CASH DISTRIBUTIONS

Cash Distributions Paid by ETP

We expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders. Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash (as defined in our Partnership Agreement) for such

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quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations.

Following are distributions declared and/or paid by us subsequent to December 31, 2013:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2013	February 7, 2014	February 14, 2014	$0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550

The total amounts of distributions declared during the periods presented (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,	
Distributions to the partners of ETP:	2014	2013
Limited Partners:		
Common Units held by public	$550	$487
Common Units held by ETE	58	178
Class H Units held by ETE Holdings	103	—
General Partner interest held by ETE	10	10
IDRs held by ETE	346	363
IDR relinquishments related to previous transactions	(115)	(86)
Total distributions declared to the partners of ETP	$952	$952

In connection with previous transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods, and ETP has agreed to make incremental distributions on the Class H Units in future periods. The net impact of these adjustments resulted in a reduction of $53 million in the distributions to be paid from ETP to ETE for the six months ended June 30, 2014. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods:

	Total Year
2014 (remainder)	$53
2015	51
2016	72
2017	50
2018	45
2019	35

In addition to the amounts reflected above, ETE has agreed, upon closing of the Susser Merger, to amend the ETP partnership agreement to provide for, among other things, the relinquishment of $350 million in the aggregate of incentive distributions that would potentially be made to ETE over the first forty fiscal quarters commencing immediately after the consummation of the merger. Such relinquishments would cease upon the agreement of an exchange of the Susser Petroleum general partner interest and the incentive distribution rights between ETE and ETP.

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.

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Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2013:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2013	February 10, 2014	February 14, 2014	$0.3313
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650

Sunoco Logistics Unit Split

On May 5, 2014, Sunoco Logistics' board of directors declared a two-for-one split of Sunoco Logistics common units. The unit split resulted in the issuance of one additional Sunoco Logistics common unit for every one unit owned as of the close of business on June 5, 2014. The unit split was effective June 12, 2014. All Sunoco Logistics unit and per unit information included in this report is presented on a post-split basis.

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

	Six Months Ended June 30,	
	2014	2013
Limited Partners:		
Common units held by public	$101	$82
Common units held by ETP	48	39
General Partner interest held by ETP	3	2
Incentive distributions held by ETP	79	53
Total distributions declared	$231	$176

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, 2013 filed with the SEC on February 27, 2014.

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, 2013, 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, 2013. Since December 31, 2013, 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, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power and barrels for natural gas liquids, crude and refined products. Dollar amounts are presented in millions.

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	June 30, 2014			December 31, 2013		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	—	$—	$—	9,457,500	$3	$5
Basis Swaps IFERC/NYMEX[1]	16,632,500	—	—	(487,500)	1	—
Swing Swaps IFERC	—	—	—	1,937,500	1	—
Power (Megawatt):						
Forwards	270,150	2	1	351,050	1	1
Futures	10,670	—	1	(772,476)	—	2
Options – Puts	(54,400)	—	—	(52,800)	—	—
Options – Calls	54,400	—	—	103,200	—	—
Crude (Bbls) – Futures	(40,000)	—	—	103,000	—	1
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(2,537,500)	—	—	570,000	—	—
Swing Swaps IFERC	26,147,500	1	1	(9,690,000)	1	—
Fixed Swaps/Futures	(4,445,000)	(4)	3	(8,195,000)	13	3
Forward Physical Contracts	(5,908,374)	—	2	5,668,559	(1)	2
Natural Gas Liquid (Bbls) – Forwards/Swaps	(1,823,200)	(7)	9	(1,133,600)	—	17
Refined Products (Bbls) – Futures	(1,605,000)	(3)	29	(280,000)	—	3
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	—	—	—	(7,352,500)	—	—
Fixed Swaps/Futures	(1,757,500)	—	—	(50,530,000)	(11)	23
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(920,000)	—	—	(1,825,000)	—	—
Fixed Swaps/Futures	(6,440,000)	(3)	3	(12,775,000)	(3)	6
Natural Gas Liquid (Bbls) – Forwards/Swaps	(510,000)	—	3	(780,000)	(1)	4
Crude (Bbls) – Futures	—	—	—	(30,000)	—	—

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

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

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Interest Rate Risk

As of June 30, 2014, we had $891 million of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $9 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, 2014	December 31, 2013
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.15% and receive a floating rate	$300	$400
ETP	July 2015[2]	Forward-starting to pay a fixed rate of 3.38% and receive a floating rate	200	—
ETP	July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	—
ETP	July 2017[4]	Forward-starting to pay a fixed rate of 4.18% and receive a floating rate	200	—
ETP	July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	—	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	—	400
ETP	February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	200	400
Panhandle	November 2021	Pay a fixed rate of 3.80% and receive a floating rate	275	275

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

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

(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(4) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $130 million as of June 30, 2014. For the $200 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $2 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled. For Panhandle's fixed to floating interest rate swaps, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $3 million.

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

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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, 2014 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

During the three months ended June 30, 2014, Sunoco Logistics implemented a new enterprise resource planning system, which includes applications to facilitate business processes such as accounting, financial reporting, and supply chain management. In connection with this transition, certain of Sunoco Logistics’ internal controls were changed or modified accordingly. None of the changes were in response to any identified deficiency or weakness in Sunoco Logistics’ internal control over financial reporting.

There have been no changes in our internal controls, other than those discussed above, 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, 2014 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2013 and Note 13 – 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, 2014.

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, 2013.

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ITEM 6. EXHIBITS

The exhibits listed below are filed or furnished, as indicated, as part of this report:

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of April 27, 2014 by and among Energy Transfer Partners, L.P., Drive Acquisition Corporation, Heritage Holdings, Inc., Energy Transfer Partners GP, L.P., Susser Holdings Corporation, and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on April 28, 2014)
10.1	Support Agreement, dated as of April 27, 2014, by and among Energy Transfer Partners, L.P., Drive Acquisition Corporation, Sam L. Susser and Susser Family Limited Partnership (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed on April 28, 2014)
10.2*	Energy Transfer Partners, L.L.C. Annual Bonus Plan effective January 1, 2014
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
*	Filed herewith.
**	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 7, 2014

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