USA TRUCK INC
Form 10-Q
October 26, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2006

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________

Commission File Number 0-19858

USA TRUCK, INC.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**71-0556971**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)

3200 Industrial Park Road	
Van Buren, Arkansas	**72956**
(Address of principal executive offices)	(Zip code)

(479) 471-2500
(Registrant s telephone number, including area code)

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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 _X_ No ___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ____ Accelerated Filer __X__ Non-Accelerated Filer _____

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No X

The number of shares outstanding of the registrant s Common Stock, par value $ .01, as of October 24, 2006 is 11,468,922.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

USA TRUCK, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	September 30, 2006 (unaudited)	December 31, 2005 (1) (audited)
Assets		
Current assets:		
Cash and cash equivalents	**$ 7,096**	$ 994
Accounts receivable:		
Trade, less allowances of $105 in 2006 and $104 in 2005	**46,493**	45,105
Other	**7,208**	6,106
Inventories	**766**	638
Deferred income taxes	**2,243**	2,329
Prepaid expenses	**4,770**	5,619
Total current assets	**68,576**	60,791
Property and equipment:		
Land and structures	**30,906**	30,320
Revenue equipment	**317,503**	284,138
Service, office and other equipment	**17,553**	17,825
	365,962	332,283
Accumulated depreciation and amortization	**(95,895)**	(85,161)
	270,067	247,122
Other assets	**158**	166
Total assets	**$ 338,801**	$ 308,079
Liabilities and stockholders equity		
Current liabilities:		
Bank drafts payable	**$ 16,483**	$ 7,416
Trade accounts payable	**15,235**	6,253
Current portion of insurance and claims accruals	**6,254**	7,779
Accrued expenses	**14,569**	10,525
Current maturities of long-term debt and capital leases	**24,932**	19,700
Note payable	**--**	1,943
Total current liabilities	**77,473**	53,616
Long-term debt and capital leases, less current maturities	**57,587**	67,589
Deferred income taxes	**38,428**	33,620
Insurance and claims accruals, less current portion	**3,130**	3,421
Stockholders equity:		
Preferred Stock, $.01 par value; 1,000 shares authorized; none issued	**--**	--
Common Stock, $.01 par value; authorized 30,000 shares in 2006 and 16,000 shares in 2005; issued 11,466 shares in 2006 and 11,415 shares in 2005	**115**	114
Additional paid-in capital	**61,875**	62,086
Retained earnings	**100,201**	88,979
Less treasury stock, at cost (1 share in 2006 and 3 shares in 2005)	**(8)**	(60)
Unearned compensation	**--**	(1,286)
Total stockholders equity	**162,183**	149,833
Total liabilities and stockholders equity	**$ 338,801**	$ 308,079

(1)The balance sheet at December 31, 2005 has been derived from the audited consolidated financial statements at that date but does not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements.

See notes to consolidated financial statements.

USA TRUCK, INC.
CONSOLIDATED STATEMENTS OF INCOME

(UNAUDITED)

(in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Revenue:				
Trucking revenue	**$ 94,558**	$ 90,552	**$ 280,782**	$ 265,785
USA Logistics revenue	**2,139**	4,996	**12,326**	13,740
Base revenue	**96,697**	95,548	**293,108**	279,525
Fuel surcharge revenue	**23,105**	17,607	**62,843**	42,086
Total revenue	**119,802**	113,155	**355,951**	321,611
Operating expenses and costs:				
Salaries, wages and employee benefits	**38,804**	36,323	**114,793**	105,959
Fuel and fuel taxes	**37,449**	32,495	**106,752**	86,338
Depreciation and amortization	**11,798**	10,576	**34,611**	30,788
Insurance and claims	**7,266**	5,844	**19,885**	18,217
Operations and maintenance	**5,489**	5,334	**16,296**	15,808
Purchased transportation	**3,447**	6,515	**16,234**	19,053
Operating taxes and licenses	**1,588**	1,563	**4,901**	4,614
Communications and utilities	**857**	828	**2,523**	2,370
Gain on disposal of revenue equipment, net	**(71)**	(219)	**(498)**	(900)
Other	**5,695**	5,053	**16,558**	14,515
Total operating expenses and costs	**112,322**	104,312	**332,055**	296,762
Operating income	**7,480**	8,843	**23,896**	24,849
Other expenses (income):				
Interest expense	**1,065**	1,202	**3,093**	3,928
Other, net	**(30)**	24	**(92)**	23
Total other expenses, net	**1,035**	1,226	**3,001**	3,951
Income before income taxes	**6,445**	7,617	**20,895**	20,898
Income tax expense	**3,030**	3,396	**9,673**	9,608
Net income	**$ 3,415**	$ 4,221	**$ 11,222**	$ 11,290
Per share information:				
Average shares outstanding (Basic)	**11,389**	10,270	**11,373**	9,603
Basic earnings per share	**$ 0.30**	$ 0.41	**$ 0.99**	$ 1.18
Average shares outstanding (Diluted)	**11,558**	10,590	**11,595**	9,899
Diluted earnings per share	**$ 0.30**	$ 0.40	**$ 0.97**	$ 1.14

See notes to consolidated financial statements.

USA TRUCK, INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

(UNAUDITED)

(in thousands)

	Common Stock Shares	Par Value	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Unearned Compensation	Total
Balance at December 31, 2005	11,415	$ 114	$ 62,086	$ 88,979	$ (60)	$ (1,286)	$ 149,833
						--	
Exercise of stock options	51	1	423	--	--	--	424
Tax benefit on exercise of stock options	--	--	40	--	--	--	40
Sale of 2 shares of Treasury Stock to Employee Stock Purchase Plan	--	--	21	--	52	--	73
Stock-based compensation	--	--	591	--	--	--	591
Elimination of unearned compensation	--	--	(1,286)	--	--	1,286	--
Net income for 2006	--	--	--	11,222	--	--	11,222
Balance at September 30, 2006	**11,466**	**$ 115**	**$ 61,875**	**$ 100,201**	**$ (8)**	**$**	

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased primarily due to Southern Union's recognition of merger-related expenses of $16 million during 2012. The remainder of the decrease was due to the impact of consolidating Southern Union's gathering and processing operations for four months during 2013 compared to nine months during 2012.

NGL Transportation and Services

	Years Ended December 31, 2013	2012	Change
NGL transportation volumes (Bbls/d)	334,853	172,569	162,284
NGL fractionation volumes (Bbls/d)	101,967	17,754	84,213
Revenues	$2,127	$650	$1,477
Cost of products sold	1,655	361	1,294
Gross margin	472	289	183
Unrealized gains on commodity risk management activities	(1)	—	(1)
Operating expenses, excluding non-cash compensation expense	(115)	(66)	(49)
Selling, general and administrative expenses, excluding non-cash compensation expense	(10)	(14)	4
Adjusted EBITDA related to unconsolidated affiliates	5	—	5
Segment Adjusted EBITDA	$351	$209	$142

Volumes. NGL transportation volumes increased due to the completion of the Gateway and Justice pipelines in December 2012 and additional NGL production as a result of bringing our Jackson and Kenedy gas processing plants in service in February 2013 and December 2012, respectively. Average daily fractionated volumes increased due to the commissioning of Lone Star’s fractionators at Mont Belvieu, Texas. 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:

	Years Ended December 31, 2013	2012	Change
Transportation margin	$187	$80	$107

Processing and fractionation margin	142	81	61
Storage margin	137	129	8
Other margin	6	(1)	7
Total gross margin	$472	$289	$183

For the year ended December 31, 2013 compared to prior year, NGL transportation and services segment gross margin increased due to the following:

- Transportation margin. Transportation margin increased as a result of higher volumes transported out of West Texas due to the completion of the Gateway pipeline, which accounted for $73 million of the increase. The completion of the Justice pipeline connection to Mont Belvieu, Texas and additional NGL production from our processing plants accounted for the remainder of the $34 million increase in transportation margin.

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- Processing and fractionation margin. Processing and fractionation margin increased due to the startup of Lone Star's fractionators in Mont Belvieu, Texas in December 2012 and October 2013, which contributed an additional $85 million during the year ended December 2013. The increase in margin from Lone Star's fractionators was offset by a $24 million decrease in margin attributable to our fractionator in Geismar, Louisiana primarily due to lower volumes.

Operating Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services operating expenses increased in 2013 primarily due to additional expenses from assets recently placed in service.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL transportation and services selling, general and administrative expenses decreased primarily due to the expiration of a transition services agreement and a decrease in employee related costs, including allocated overhead expenses.

Investment in Sunoco Logistics

	Years Ended December 31,		
	2013	2012	Change
Revenue	$16,639	$3,189	$13,450
Cost of products sold	15,574	2,885	12,689
Gross margin	1,065	304	761
Unrealized gains on commodity risk management activities	(1)	(15)	14
Operating expenses, excluding non-cash compensation expense	(117)	(48)	(69)
Selling, general and administrative expenses, excluding non-cash compensation expense	(110)	(32)	(78)
Adjusted EBITDA related to unconsolidated affiliates	41	10	31
Other	(7)	—	(7)
Segment Adjusted EBITDA	$871	$219	$652

We obtained control of Sunoco Logistics on October 5, 2012 in connection with our acquisition of Sunoco; therefore, the results for the year ended December 31, 2012 only reflect results from October 5, 2012 to December 31, 2012 compared to a full twelve months of results during the year ended December 31, 2013.

Retail Marketing

	Years Ended December 31,		
	2013	2012	Change
Total retail gasoline outlets, end of period	5,112	4,988	124
Total company-operated outlets, end of period	513	437	76
Gasoline and diesel throughput per company-operated site (gallons/month)	200,087	198,000	2,087
Revenue	$21,012	$5,926	$15,086
Cost of products sold	20,150	5,757	14,393
Gross margin	862	169	693
Unrealized gains on commodity risk management activities	(1)	—	(1)
Operating expenses, excluding non-cash compensation expense	(435)	(119)	(316)
Selling, general and administrative expenses, excluding non-cash compensation expense	(101)	(17)	(84)
LIFO valuation adjustments	(3)	75	(78)
Adjusted EBITDA related to unconsolidated affiliates	4	1	3
Other	(1)	—	(1)
Segment Adjusted EBITDA	$325	$109	$216

We acquired our retail marketing segment on October 5, 2012 in connection with our acquisition of Sunoco; therefore, the results for the year ended December 31, 2012 only reflect results from October 5, 2012 to December 31, 2012 compared to a full twelve

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months of results during the year ended December 31, 2013. Segment Adjusted EBITDA also increased by $10 million as a result of the MACS acquisition in October 2013.

All Other

	Years Ended December 31,		
	2013	2012	Change
Revenue	$2,367	$1,555	$812
Cost of products sold	2,309	1,496	813
Gross margin	58	59	(1)
Unrealized (gains) losses on commodity risk management activities	(2)	5	(7)
Operating expenses, excluding non-cash compensation expense	(31)	(57)	26
Selling, general and administrative expenses, excluding non-cash compensation expense	(106)	(119)	13
Adjusted EBITDA related to discontinued operations	76	84	(8)
Adjusted EBITDA related to unconsolidated affiliates	213	166	47
Other	(4)	—	(4)
Elimination	(10)	(12)	2
Segment Adjusted EBITDA	$194	$126	$68

Amounts reflected in our all other segment primarily include:

- our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas in January 2012. Our investment in AmeriGas was reflected in the all other segment subsequent to that transaction;
- Southern Union’s local distribution operations beginning March 26, 2012;
- our natural gas compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture, effective upon our acquisition of Sunoco on October 5, 2012;
- our investment in Regency related to the Regency common and Class F units received by Southern Union in exchange of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013; and
- our natural gas marketing operations.

The decrease in operating expenses for the year ended December 31, 2013 compared to last year was primarily due to the recognition of $18 million of operating expenses from our retail propane operations prior to the deconsolidation of those operations in January 2012.

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

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

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

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Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011

Consolidated Results

	Years Ended December 31,		
	2012	2011	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$601	$667	$(66)
Interstate transportation and storage	1,013	373	640
Midstream	467	421	46
NGL transportation and services	209	127	82
Investment in Sunoco Logistics	219	—	219
Retail marketing	109	—	109
All other	126	193	(67)
Total	2,744	1,781	963
Depreciation and amortization	(656)	(405)	(251)
Interest expense, net of interest capitalized	(665)	(474)	(191)
Gain on deconsolidation of Propane Business	1,057	—	1,057
Losses on interest rate derivatives	(4)	(77)	73
Non-cash unit-based compensation expense	(42)	(38)	(4)
Unrealized losses on commodity risk management activities	(9)	(11)	2
LIFO valuation adjustments	(75)	—	(75)
Loss on extinguishment of debt	(115)	—	(115)
Adjusted EBITDA related to discontinued operations	(99)	(23)	(76)
Adjusted EBITDA related to unconsolidated affiliates	(480)	(56)	(424)
Equity in earnings of unconsolidated affiliates	142	26	116
Other, net	22	(4)	26
Income from continuing operations before income tax expense	1,820	719	1,101
Income tax expense from continuing operations	(63)	(19)	(44)
Income from continuing operations	1,757	700	1,057
Loss from discontinued operations	(109)	(3)	(106)
Net income	$1,648	$697	$951

See the detailed discussion of Segment Adjusted EBITDA below.

The year ended December 31, 2012 was impacted by multiple transactions. Additional information has been provided in "Supplemental Pro Forma Information" below, which provides pro forma information assuming the transactions had occurred at the beginning of the period.

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

- depreciation and amortization related to Southern Union of $179 million from March 26, 2012 through December 31, 2012;
- depreciation and amortization related to Sunoco Logistics and Sunoco of $63 million and $32 million, respectively, from October 5, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2011 and 2012.

These increases in depreciation and amortization were offset by the impact from the January 2012 deconsolidation of the Propane Business, for which our consolidated results reflected $4 million and $82 million in depreciation and amortization for the years ended December 31, 2012 and 2011, respectively.

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Interest Expense. Interest expense increased primarily due to:

- interest expense recorded by Southern Union of $130 million from March 26, 2012 through December 31, 2012;
- interest expense related to Sunoco Logistics and Sunoco of $14 million and $9 million, respectively, from October 5, 2012 through December 31, 2012; and,
- incremental interest expense due to the issuance of $1.5 billion of senior notes in May 2011 to fund the LDH acquisition and the issuance of $2.0 billion of senior notes in January 2012 to fund the Citrus Acquisition; offset by
- a reduction of several series of our higher coupon notes that were repurchased in the tender offers completed in January 2012; and,
- an increase in capitalized interest related to our growth projects.

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

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

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

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized in January 2012 in connection with our tender offers in which we repurchased approximately $750 million in aggregate principal amount of Senior Notes.

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

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected for 2012 primarily include our proportionate share of such amounts related to AmeriGas, Citrus and FEP. The 2011 amounts primarily represented our proportionate share of such amounts for FEP only. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

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

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

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Supplemental Information on Unconsolidated Affiliates

The following table presents equity in earnings of unconsolidated affiliates, the proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes by unconsolidated affiliate, Adjusted EBITDA related to unconsolidated affiliates and distributions received from affiliates for the years ended December 31, 2012 and 2011:

	Years Ended December 31,		
	2012	2011	Change
Equity in earnings (losses) of unconsolidated affiliates:			
AmeriGas	$(4)	$—	$(4)
Citrus	65	—	65
FEP	55	24	31
Other	26	2	24
Total equity in earnings of unconsolidated affiliates	$142	$26	$116
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:			
AmeriGas	$143	$—	$143
Citrus	163	—	163
FEP	22	29	(7)
Other	10	1	9
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$338	$30	$308
Adjusted EBITDA related to unconsolidated affiliates:			
AmeriGas	$139	$—	$139
Citrus	228	—	228
FEP	77	53	24
Other	36	3	33
Total Adjusted EBITDA related to unconsolidated affiliates	$480	$56	$424
Distributions received from unconsolidated affiliates:			
AmeriGas	$94	$—	$94
Citrus	88	—	88
FEP	70	46	24
Other	10	5	5
Total distributions received from unconsolidated affiliates	$262	$51	$211

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Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)	9,849,900	11,295,084	(1,445,184)
Revenues	$2,191	$2,674	$(483)
Cost of products sold	1,394	1,774	(380)
Gross margin	797	900	(103)
Unrealized losses on commodity risk management activities	19	9	10
Operating expenses, excluding non-cash compensation expense	(191)	(210)	19
Selling, general and administrative, excluding non-cash compensation expense	(25)	(35)	10
Adjusted EBITDA related to unconsolidated affiliates	1	3	(2)
Segment Adjusted EBITDA	$601	$667	$(66)

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

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

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

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

- Transportation fees. Transport fees decreased primarily due to a decrease in transported volumes as unfavorable market conditions continued and the cessation of certain long-term transportation contracts;

From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $28 million in 2012 compared to $36 million in 2011. The decrease of $8 million between periods was primarily due to a reduction in the amount of capacity utilized by our marketing affiliate;

- Natural gas sales and other. Margin from natural gas sales and other activity decreased primarily due to a decline of $30 million in margin where we utilize third party processing, offset by increased margin of $13 million from wellhead purchases in the Eagle Ford Shale that were sold to end users on our HPL system and increased margin of $4 million from system optimization and other operational activities.

The margin from the natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. Excluding derivatives related to storage, unrealized gains of $13 million were recorded in 2012 as compared to unrealized losses of $21 million in 2011; and

- Retained fuel revenues. Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased $51 million due to less retained volumes and a $37 million decline in the average of natural gas spot prices.

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Storage margin was comprised of the following:

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

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

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

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

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

Interstate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)	6,811,339	2,800,655	4,010,684
Natural gas sold (MMBtu/d)	18,065	22,405	(4,340)
Revenues	$1,109	$447	$662
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(257)	(103)	(154)
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(143)	(24)	(119)
Adjusted EBITDA related to unconsolidated affiliates	304	53	251
Segment Adjusted EBITDA	$1,013	$373	$640

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

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

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

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

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

Midstream

	Years Ended December 31,		
	2012	2011	Change
Gathered volumes (MMBtu/d):			
ETP legacy assets	2,364,133	2,020,126	344,007
Southern Union gathering and processing	510,061	—	510,061
NGLs produced (Bbls/d):			
ETP legacy assets	79,640	54,246	25,394
Southern Union gathering and processing	41,163	—	41,163
Equity NGLs produced (Bbls/d):			
ETP legacy assets	17,314	16,385	929
Southern Union gathering and processing	7,437	—	7,437
Revenues	$1,953	$1,483	$470
Cost of products sold	1,273	988	285
Gross margin	680	495	185
Operating expenses, excluding non-cash compensation expense	(165)	(87)	(78)
Selling, general and administrative, excluding non-cash compensation expense	(56)	(10)	(46)
Adjusted EBITDA related to discontinued operations	15	23	(8)
Adjusted EBITDA related to unconsolidated affiliates	(7)	—	(7)
Segment Adjusted EBITDA	$467	$421	$46

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

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

	Years Ended December 31,		
	2012	2011	Change
Gathering and processing fee-based revenues	$339	$253	$86
Non fee-based contracts and processing	335	234	101
Other	6	8	(2)
Total gross margin	$680	$495	$185

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

- Gathering and processing fee-based revenues. Increased volumes from production in the Eagle Ford Shale resulted in increased fee-based revenues of $70 million in 2012 as compared to 2011, partially offset by declines in the Fort Worth Basin that affected our North Texas system resulting in a $5 million decline from 2012 to 2011. Additionally, Southern Union's gathering and processing segment contributed $20 million of fee-based revenue during March 26, 2012 through December 31, 2012.
- Non fee-based contracts and processing margin. We recorded $125 million of incremental non-fee based revenue in connection with the consolidation of Southern Union's gathering and processing business from March 26, 2012 through December 31, 2012. Excluding these incremental revenues from Southern Union's gathering and processing business, our non fee-based gross margins decreased $24 million primarily due to lower NGL prices. The composite NGL price for 2012 was $0.96 per gallon as compared to $1.30 per gallon in 2011.

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

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to consolidation of Southern Union's gathering and processing operations effective March 26, 2012. For the periods presented, selling, general and administrative expenses increased approximately $38 million due to consolidation of Southern Union's gathering and processing operations. In addition, growth from assets placed into service in the Eagle Ford Shale resulted in $8 million of additional selling, general and administrative expenses.

NGL Transportation and Services

	Years Ended December 31,		
	2012	2011	Change
NGL transportation volumes (Bbls/d)	172,569	132,862	39,707
NGL fractionation volumes (Bbls/d)	17,754	16,475	1,279
Revenues	$650	$397	$253
Cost of products sold	361	218	143
Gross margin	289	179	110
Operating expenses, excluding non-cash compensation expense	(66)	(43)	(23)
Selling, general and administrative, excluding non-cash compensation expense	(14)	(9)	(5)
Adjusted EBITDA related to unconsolidated affiliates	—	—	—
Segment Adjusted EBITDA	$209	$127	$82

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

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

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

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

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

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

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

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

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL Transportation and Storage selling, general and administrative expenses increased due to operations of Lone Star for twelve months in 2012 compared to eight months in 2011.

Investment in Sunoco Logistics

	Years Ended December 31,		
	2012	2011	Change
Revenue	$3,189	$—	$3,189
Cost of products sold	2,885	—	2,885
Gross margin	304	—	304
Unrealized gains on commodity risk management activities	(15)	—	(15)
Operating expenses, excluding non-cash compensation expense	(48)	—	(48)
Selling, general and administrative, excluding non-cash compensation expense	(32)	—	(32)
Adjusted EBITDA related to unconsolidated affiliates	10	—	10
Segment Adjusted EBITDA	$219	$—	$219

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

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Retail Marketing

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

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

All Other

	Years Ended December 31,		
	2012	2011	Change
Revenue	$1,555	$2,888	$(1,333)
Cost of products sold	1,496	2,274	(778)
Gross margin	59	614	(555)
Unrealized losses on commodity risk management activities	5	1	4
Operating expenses, excluding non-cash compensation expense	(57)	(355)	298
Selling, general and administrative, excluding non-cash compensation expense	(119)	(57)	(62)
Adjusted EBITDA related to discontinued operations	84	—	84
Adjusted EBITDA related to unconsolidated affiliates	166	—	166
Elimination	(12)	(10)	(2)
Segment Adjusted EBITDA	$126	$193	$(67)

For 2011, our all other segment included our retail propane and other retail propane business, as well as certain other businesses. In January 2012, we contributed the Propane Business to AmeriGas. In 2012, amounts reflected in our all other segment primarily include:

- our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas in January 2012. Our investment in AmeriGas was reflected in the all other segment subsequent to that transaction;
- Southern Union’s local distribution operations beginning March 26, 2012;
- our natural gas compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture, effective upon our acquisition of Sunoco on October 5, 2012; and
- our natural gas marketing operations.

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Supplemental Pro Forma Financial Information

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

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

	ETP Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$15,702	$(93)	$35,258	$443	$(12,174)	$39,136
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	13,217	(80)	33,142	302	(11,193)	35,388
Depreciation and amortization	656	(4)	168	49	76	945
Selling, general and administrative	435	(1)	459	11	(119)	785
Impairment charges	—		124		(22)	102
Total costs and expenses	14,308	(85)	33,893	362	(11,258)	37,220
OPERATING INCOME	1,394	(8)	1,365	81	(916)	1,916
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(665)	(24)	(123)	(50)	2	(860)
Equity in earnings of affiliates	142	19	41	16	5	223
Gain on deconsolidation of Propane Business	1,057	(1,057)	—	—	—	—
Gain on formation of Philadelphia Energy Solutions	—	—	1,144	—	(1,144)	—
Loss on extinguishment of debt	(115)	115	—	—	—	—
Losses on interest rate derivatives	(4)	—	—	—	—	(4)
Other, net	11	2	118	(2)	(2)	127
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	1,820	(953)	2,545	45	(2,055)	1,402
Income tax expense (benefit)	63	—	956	12	(871)	160
INCOME FROM CONTINUING OPERATIONS	$1,757	$(953)	$1,589	$33	$(1,184)	$1,242

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

	ETP Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$6,799	$(1,427)	$45,328	$1,997	$(16,528)	$36,169
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	4,974	(1,174)	44,119	1,338	(16,677)	32,580
Depreciation and amortization	405	(78)	335	204	(2)	864
Selling, general and administrative	173	(47)	598	42	(56)	710
Impairment charges	—	—	2,629	—	(2,569)	60
Total costs and expenses	5,552	(1,299)	47,681	1,584	(19,304)	34,214
OPERATING INCOME	1,247	(128)	(2,353)	413	2,776	1,955
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(474)	(40)	(172)	(218)	29	(875)
Equity in earnings of affiliates	26	148	15	99	(158)	130
Losses on interest rate derivatives	(77)	—	—	—	—	(77)
Impairment charges	(5)	—	—	—	—	(5)
Other, net	2	2	44	—	(2)	46
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	719	(18)	(2,466)	294	2,645	1,174
Income tax expense (benefit)	19	(4)	(1,063)	80	1,070	102
INCOME FROM CONTINUING OPERATIONS	$700	$(14)	$(1,403)	$214	$1,575	$1,072

(a) Propane Transaction adjustments reflect the following:

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

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

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

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

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

The adjustment to equity in earnings of affiliates reflects the reversal of amounts related to Citrus Corp. recorded in Southern Union’s historical income statements.

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- The adjustment to income tax expense includes the pro forma impact resulting from the pro forma adjustments to pre-tax income of Sunoco and Southern Union.

Liquidity and Capital Resources

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 the following capital expenditures in 2014 to be within the following ranges:

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

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

The assets used in 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.

As of December 31, 2013, in addition to $549 million of cash on hand, we had available capacity under our revolving credit facilities of $2.34 billion. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2014; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

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

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

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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.
Following is a summary of operating activities by period:
Year Ended December 31, 2013
Cash provided by operating activities in 2013 was $2.37 billion and net income was $768 million. The difference between net income and cash provided by operating activities in 2013 primarily consisted of non-cash items totaling $1.52 billion offset by net changes in operating assets and liabilities of $146 million. The non-cash activity in 2013 consisted primarily of depreciation and amortization of $1.03 billion, a goodwill impairment of $689 million, and deferred income taxes of $48 million offset slightly by the gain on the sale of AmeriGas common units of $87 million.
Year Ended December 31, 2012
Cash provided by operating activities in 2012 was $1.20 billion and net income was $1.65 billion. The difference between net income and cash provided by operating activities in 2012 primarily consisted of the gain on deconsolidation of our Propane Business of $1.06 billion and net changes in operating assets and liabilities of $475 million offset by non-cash items totaling $1.10 billion. The non-cash activity in 2012 consisted primarily of depreciation and amortization, including amounts related to discontinued operations, of $656 million, the write-down of assets included in loss from discontinued operations of $132 million and non-cash compensation expense of $42 million.
Year Ended December 31, 2011
Cash provided by operating activities in 2011 was $1.34 billion and net income was $697 million. The difference between net income and cash provided by operating activities in 2011 consisted of non-cash items totaling $486 million and changes in operating assets and liabilities of $166 million. The non-cash activity in 2011 consisted primarily of depreciation and amortization, including amounts related to discontinued operations, of $431 million and non-cash compensation expense of $37 million.
Investing Activities
Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash distributions from our joint ventures, and cash proceeds from sales or contributions of assets or businesses. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.
Following is a summary of investing activities by period:
Year Ended December 31, 2013
Cash used in investing activities in 2013 was $2.46 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $2.52 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, we received $504 million, $1.01 billion, and $346 million in cash from the SUGS Contribution, the sale of the MGE and NEG assets, and the sale of AmeriGas common units, respectively, and paid net cash of $1.74 billion for acquisitions, primarily for the Holdco Acquisition and MACS.
Year Ended December 31, 2012
Cash used in investing activities in 2012 was $2.29 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $2.81 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2012 we paid net

cash of $1.36 billion for acquisitions, primarily including amounts related to Citrus and Sunoco. We also received net cash proceeds of $1.44 billion from the contribution of the Propane Business.

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Year Ended December 31, 2011

Cash used in investing activities in 2011 was $3.55 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $1.39 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2011 we paid cash for acquisitions of $1.97 billion, primarily for the LDH Acquisition, and made net advances to our joint ventures of $200 million.

Following is a summary of our capital expenditures (net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Year Ended December 31, 2013:					
Intrastate transportation and storage	$18	$29	$47	$(3)	$44
Interstate transportation and storage	55	97	152	18	170
Midstream[1]	516	49	565	87	652
NGL transportation and services[2]	426	17	443	84	527
Investment in Sunoco Logistics	965	53	1,018	(121)	897
Retail marketing	113	63	176	(1)	175
All other (including eliminations)	19	35	54	4	58
Total	$2,112	$343	$2,455	$68	$2,523
Year Ended December 31, 2012:					
Intrastate transportation and storage	$8	$29	$37	$2	$39
Interstate transportation and storage	5	128	133	1	134
Midstream	1,265	52	1,317	(153)	1,164
NGL transportation and services	1,288	14	1,302	(75)	1,227
Investment in Sunoco Logistics	118	21	139	—	139
Retail marketing	38	20	58	(19)	39
All other (including eliminations)	14	49	63	—	63
Total	$2,736	$313	$3,049	$(244)	$2,805
Year Ended December 31, 2011:					
Intrastate transportation and storage	$12	$41	$53	$3	$56
Interstate transportation and storage	177	30	207	32	239
Midstream	809	28	837	(46)	791
NGL transportation and services	317	8	325	(81)	244
All other (including eliminations)	35	27	62	(1)	61
Total	$1,350	$134	$1,484	$(93)	$1,391

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

(2) We received $147 million in capital contributions from Regency related to their 30% share of Lone Star.

Financing Activities

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

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Following is a summary of financing activities by period:

Year Ended December 31, 2013

Cash provided by financing activities was $325 million in 2013. We received $1.61 billion in net proceeds from Common Unit offerings. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, and acquisitions, as well as for general partnership purposes. In 2013, we had a net increase in our debt level of $819 million primarily due to ETP's issuance of $1.25 billion and $1.50 billion in aggregate principal amount of senior notes in January 2013 and September 2013, respectively, and Sunoco Logistics' issuance of $700 million in aggregate principal amount of senior notes in January 2013 (see Note 6 to our consolidated financial statements) partially offset by repayments of long-term debt and credit facilities of $2.71 billion in the aggregate. In connection with the issuance of senior notes, we incurred debt issuance costs of $32 million. In 2013, we paid distributions of $1.80 billion to our partners and we paid distributions of $382 million to noncontrolling interests. In addition, we received capital contributions of $147 million from Regency for its noncontrolling interest in Lone Star.

Year Ended December 31, 2012

Cash provided by financing activities was $1.29 billion in 2012. We received $791 million in net proceeds from Common Unit offerings. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, acquisitions, and capital contributions to joint ventures, as well as for general partnership purposes. In 2012, we had a net increase in our debt level of $1.78 billion primarily due to our issuance of $2.00 billion in aggregate principal amount of senior notes in January 2012 to fund the Citrus Acquisition, partially offset by the repurchase of $750 million in aggregate principal amount of senior notes in connection with our tender offers announced in January 2012. In connection with the issuance of senior notes in January 2012, we incurred debt issuance costs of $18 million. In 2012, we paid distributions of $1.34 billion to our partners. In addition, we received capital contributions of $320 million from Regency for its noncontrolling interest in Lone Star.

Year Ended December 31, 2011

Cash provided by financing activities was $2.27 billion in 2011. We received $1.47 billion in net proceeds from Common Unit offerings, including $96 million under our equity distribution program. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, acquisitions, and capital contributions to joint ventures, as well as for general partnership purposes. In 2011, we had a net increase in our debt level of $1.38 billion primarily due to our issuance of $1.50 billion of senior notes in May 2011 to partially fund the LDH Acquisition. We also received $645 million of capital contributions from Regency for its noncontrolling interest related to the LDH Acquisition. In 2011, we paid distributions of $1.16 billion to our partners.

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Description of Indebtedness

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

	December 31, 2013	2012
ETP Senior Notes	$11,182	$7,692
Transwestern Senior Unsecured Notes	870	870
Southern Union Senior Notes	169	1,260
Panhandle Senior Notes	916	1,621
Sunoco Senior Notes	965	965
Sunoco Logistics Senior Notes	2,150	1,450
Revolving credit facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Note Payable to ETE	—	166
Other long-term debt	228	32
Unamortized premiums, net of discounts and fair value adjustments	308	417
Total debt	17,088	16,217
Less: current maturities	637	609
Long-term debt, less current maturities	$16,451	$15,608

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

January 2013 Senior Notes Offerings

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

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

September 2013 Senior Notes Offering

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

Note Exchange

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

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

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

We use the ETP Credit Facility to provide temporary financing for our growth projects, as well as for general partnership purposes. We typically repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term notes offerings. The timing of borrowings depends on the Partnership's activities and the cash available to fund those activities. The repayments of amounts outstanding under the ETP Credit Facility depend on multiple factors, including market conditions and expectations of future working capital needs, and ultimately are a financing decision made by management. Therefore, the balance outstanding under the ETP Credit Facility may vary significantly between periods. We do not believe that such fluctuations indicate a significant change in our liquidity position, because we expect to continue to be able to repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term note offerings.

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

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

Southern Union Credit Facility

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

Sunoco Logistics Credit Facilities

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

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

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

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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

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The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The credit agreement relating to the ETP Credit Facility also contains a financial covenant that provides that the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1 as of the end of each quarter, with a permitted increase to 5.5 to 1 during a Specified Acquisition Period, as defined in the ETP Credit Facility.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of all or substantially all assets and the payment of dividends and specify a maximum debt to capitalization ratio.

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

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

Covenants Related to Southern Union

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

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

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

Covenants Related to Sunoco Logistics

Sunoco Logistics' $1.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1

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during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

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

Contingent Residual Support Agreement – AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6 of our consolidated financial statements, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550 million in aggregate principal amount of 6.75% Senior Notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% Senior Notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the contribution of the Propane Business, ETP entered into a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt.

PEPL Holdings Guarantee of Collection

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

Contractual Obligations

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

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$16,780	$812	$1,422	$2,425	$12,121
Interest on long-term debt[1]	13,706	973	1,762	1,582	9,389
Payments on derivatives	74	35	39	—	—
Purchase commitments[2]	25,512	12,197	7,883	2,175	3,257
Transportation, natural gas storage and fractionation contracts	122	33	48	37	4
Operating lease obligations	767	80	148	119	420
Other	246	77	89	56	24
Total[3]	$57,207	$14,207	$11,391	$6,394	$25,215

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2013. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2013. To the extent interest rates change, our contractual obligations for interest payments will change. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for further discussion.

(2) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be

purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for refined product and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts

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approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the December 31, 2013 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated. Approximately $5.72 billion of total purchase commitments relate to production from PES.

(3) Excludes non-current deferred tax liabilities of $3.76 billion due to uncertainty of the timing of future cash flows for such liabilities.

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 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.

Distributions declared are summarized as follows:

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

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

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The total amounts of distributions declared during the periods presented (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate):

	Years Ended December 31,		
	2013	2012	2011
Distributions to the partners of ETP:			
Limited Partners:			
Common units held by public	$1,005	$783	$582
Common units held by ETE	268	180	180
Class H Units held by ETE Holdings	105	—	—
General Partner interest held by ETE	20	20	20
IDRs held by ETE	701	529	422
IDR relinquishments related to previous transactions	(199)	(90)	—
Total distributions to the partners of ETP	$1,900	$1,422	$1,204

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

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

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

As discussed in Note 7 to our consolidated financial statements, ETP has agreed to make incremental cash distributions in the aggregate amount of $329 million to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017, in respect of the Class H units as a means to offset prior IDR subsidies that ETE agreed to in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition.

In addition to the amounts above, in connection with the Partnership's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of incentive distributions of $50 million, $50 million, $45 million and $35 million for the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

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

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

2019	8.75	8.75	8.75	8.75	35.0

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Cash Distributions Paid by Sunoco Logistics

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

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

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

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

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

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

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

New Accounting Standards

None.

Estimates and Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules, and we believe the proper implementation and consistent application of the accounting rules are critical. Our critical accounting policies are discussed below. For further details on our accounting policies see Note 2 to our consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2013 represent the actual results in all material respects.

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

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

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

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

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

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

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

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

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

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

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

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

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

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

Regulatory Assets and Liabilities. Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management’s assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Accounting for Derivative Instruments and Hedging Activities. We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and refined products. These contracts consist primarily of futures and swaps. In addition, prior to the contribution of our retail propane activities to AmeriGas, we used derivatives to limit our exposure to propane market prices.

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

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that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

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

We utilize published settlement prices for exchange-traded contracts, quotes provided by brokers, and estimates of market prices based on daily contract activity to estimate the fair value of these contracts. Changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" for further discussion regarding our derivative activities.

Fair Value of Financial Instruments. We have marketable securities, commodity derivatives 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 over-the-counter commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable.

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

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

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

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million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, we recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

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

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

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

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

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

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

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

Pensions and Other Postretirement Benefit Plans

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

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

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

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

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

For more information on our litigation and contingencies, see Note 10 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data” in this report.

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

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

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

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

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

Deferred Income Taxes. ETP recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards (“NOLs”) and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce

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

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend "believe," "may," "will" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected.

Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;

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- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Item 1A. Risk Factors” in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

Inflation

Interest rates on existing and future credit facilities and future debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and has not had a material effect on our results of operations. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by commodity price changes. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along a portion of increased costs to our customers in the form of higher fees.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For certain of our activities, 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 over-the-counter commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to reduce market exposure and price risk within our segments as follows:

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling forward financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention natural gas in excess of consumption, a portion of volumes purchased at the wellhead from producers,

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and location price differentials related to the transportation of natural gas. Additionally, we use derivatives for trading purposes in this segment.

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We also use derivative swap contracts to mitigate risk from price fluctuations on NGLs we retain for fees in our midstream segment.
- Sunoco Logistics uses derivative contracts as economic hedges against price changes related to its forecasted refined products and NGL purchase and sale activities.
- In our all other segment, we utilized derivatives for trading purposes.

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

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

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

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

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

Sunoco Logistics manages exposures to crude oil, refined products and NGL commodity prices by monitoring inventory levels and expectations of future commodity prices when making decisions with respect to risk management and inventory carried. Sunoco Logistics’ policy is to purchase only commodity products for which it has a market and to structure its sales contracts so that price fluctuations for those products do not materially affect the margin Sunoco Logistics receives. Sunoco Logistics also seeks to maintain a position that is substantially balanced within its various commodity purchase and sale activities. Sunoco Logistics may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances, as well as logistical issues associated with inclement weather conditions. When unscheduled inventory builds or draws do occur, they are monitored and managed to a balanced position over a reasonable period of time.

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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 and refined products. Dollar amounts are presented in millions.

	December 31, 2013			December 31, 2012		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	9,457,500	$3	$5	—	$—	$—
Basis Swaps IFERC/NYMEX[(1)]	(487,500)	1	—	(30,980,000)	(6)	—
Swing Swaps	1,937,500	1	—	—	—	—
Power (Megawatt):						
Forwards	351,050	1	1	19,650	—	1
Futures	(772,476)	—	2	(1,509,300)	(1)	1
Options – Puts	(52,800)	—	—	—	—	—
Options – Calls	103,200	—	—	1,656,400	2	1
Crude (Bbls) – Futures	103,000	—	1	—	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	570,000	—	—	150,000	(1)	—
Swing Swaps IFERC	(9,690,000)	1	—	(83,292,500)	1	1
Fixed Swaps/Futures	(8,195,000)	13	3	27,077,500	(7)	9
Forward Physical Contracts	5,668,559	(1)	2	11,689,855	—	2
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	—	3	(30,000)	—	—
Refined Products (Bbls) – Futures	(1,133,600)	—	17	(666,000)	(3)	14
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(7,352,500)	—	—	(18,655,000)	(1)	—
Fixed Swaps/Futures	(50,530,000)	(11)	23	(44,272,500)	4	15
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(1,825,000)	—	—	—	—	—
Fixed Swaps/Futures	(12,775,000)	(3)	6	(8,212,500)	(3)	3
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	(1)	4	(930,000)	(2)	7
Refined Products (Bbls) – Futures	—	—	—	(98,000)	—	1
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

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assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of December 31, 2013, we had $907 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 December 31, 2013	December 31, 2012
ETP	July 2013(2)	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$—	$400
ETP	July 2014(2)	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union(3)	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union(3)	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

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

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date. During the year ended December 31, 2013, we settled $400 million of ETP’s forward-starting interest rate swaps that had an effective date of July 2013.

(3) In connection with the Panhandle Merger, Southern Union’s interest rate swaps outstanding were assumed by Panhandle.

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 $29 million as of December 31, 2013. For the $1.4 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $14 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled. For Southern Union’s 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.

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

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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.

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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2013.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Partners, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 1992 Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2013.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2013, as stated in their report, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the internal control over financial reporting of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013, based on criteria established in the 1992 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2013, and our report dated February 27, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner manages and directs all of our activities. The activities of our General Partner are managed and directed by its general partner, ETP LLC, which we refer to in this Item as “our General Partner.” Our officers and directors are officers and directors of ETP LLC. ETE, as the sole member of ETP LLC, is entitled under the limited liability company agreement of ETP LLC to appoint all of the directors of ETP LLC. This agreement provides that the Board of Directors of ETP LLC shall consist of not more than 13 persons, at least three of whom are required to qualify as independent directors. As of December 31, 2013, our Board of Directors was comprised of seven persons, four of whom qualified as “independent” under the NYSE’s corporate governance standards. Our Board of Directors has determined that Messrs. Collins, Glaske, Grimm, and Skidmore all meet the NYSE’s independence requirements. Our current directors who are not independent consist of Kelcy L. Warren, ETP LLC’s Chief Executive Officer, and Marshall S. McCrea III, ETP LLC’s President and Chief Operating Officer, as well as Jamie Welch, the Group Chief Financial Officer of ETE’s general partner.

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

Board Leadership Structure. We have no policy requiring either that the positions of the Chairman of the Board and the Chief Executive Officer, or CEO, be separate or that they be occupied by the same individual. The Board of Directors believes that this issue is properly addressed as part of the succession planning process and that a determination on this subject should be made when it elects a new chief executive officer or at such other times as when consideration of the matter is warranted by circumstances. Currently, the Board of Directors believes that the CEO is best situated to serve as Chairman because he is the director most familiar with the Partnership’s business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. Our independent directors bring experience, oversight and expertise from outside the Partnership and from a variety of industries, while the CEO brings extensive experience and expertise specifically related to the Partnership’s business. The Board of Directors believes that the current combined role of Chairman and CEO promotes strategy development and execution, and facilitates information flow between management and the Board of Directors, which are essential to effective governance.

One of the key responsibilities of the Board of Directors is to develop strategic direction and hold management accountable for the execution of strategy once it is developed. The Board of Directors believes the current combined role of Chairman and CEO, together with a majority of independent board members, is in the best interest of Unitholders because it provides the appropriate balance between strategy development and independent oversight of management.

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

Corporate Governance

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

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

Annual Certification

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this annual report. In 2013, our CEO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Partnership and its Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Partnership. Pursuant to the terms of our partnership agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in Item 1A. Risk Factors in this annual report).

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407 (d)(5) of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee members Paul E. Glaske and David K. Skidmore qualified as Audit Committee financial experts during 2013. A description of the qualifications of Mr. Glaske and Mr. Skidmore may be found elsewhere in this Item under "Directors and Executive Officers of the General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by auditing standards, and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Board of Directors adopts the charter for the Audit Committee. Paul E. Glaske, Michael K. Grimm and David K. Skidmore currently serve on the Audit Committee and Mr. Glaske serves as the chairman of the Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, our Board of Directors has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans adopted by our Unitholders, including the performance standards or other restrictions pertaining to the vesting of any such awards. Pursuant to the charter of the Compensation Committee, a director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, the Partnership or its subsidiaries. Michael K. Grimm and David K. Skidmore serve as the members of the Compensation Committee and Mr. Grimm serves as the chairman of the Compensation Committee. Our Board of Directors has determined that both Messrs. Grimm and Skidmore are “independent” (as that term is defined in the applicable NYSE corporate governance standards).

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The Compensation Committee's responsibilities include, among other duties, the following:

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

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

Code of Business Conduct and Ethics

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

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. The Chairman of each of our Audit and Compensation Committee alternate as the presiding director of such meetings.

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

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Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of February 27, 2014. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	58	Chief Executive Officer and Chairman of the Board of Directors
Marshall S. (Mackie) McCrea, III	54	President, Chief Operating Officer and Director
Martin Salinas, Jr.	42	Chief Financial Officer
Jamie Welch	47	Director and ETE Group Chief Financial Officer and Head of Business Development
Thomas P. Mason	57	Senior Vice President, General Counsel and Secretary
Richard Cargile	54	President of Midstream Operations
Paul E. Glaske	80	Director
Ted Collins, Jr.	75	Director
Michael K. Grimm	59	Director
David K. Skidmore	58	Director

Messrs. Warren, McCrea and Welch also serve as directors of ETE's general partner.

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

Kelcy L. Warren. Mr. Warren is the Chief Executive Officer and Chairman of the Board of our General Partner and has served in that capacity since August 2007. Prior to that, Mr. Warren had served as the Co-Chief Executive Officer and Co-Chairman of the Board of our General Partner since the combination of the midstream and intrastate transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Warren served as President of the general partner of ET Company I, Ltd., having served in that capacity since 1996. From 1996 to 2000, he also served as a director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 25 years of business experience in the energy industry. The Board of Directors selected Mr. Warren to serve as a director and as Chairman because he is the Partnership's Chief Executive Officer and has more than 25 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.

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

Martin Salinas, Jr. Mr. Salinas has served as Chief Financial Officer of our General Partner since June 2008. Mr. Salinas had previously served as our Controller and Treasurer from September 2004 to June 2008. Prior to joining ETP, Mr. Salinas was a Senior Audit Manager with KPMG in San Antonio, Texas from September 2002. Mr. Salinas earned his B.B.A. in Accounting from the University of Texas at San Antonio in 1994 and is a Certified Public Accountant. Mr. Salinas also serves on the Board of Directors of the general partner of Sunoco Logistics.

Jamie Welch. Mr. Welch is the Group Chief Financial Officer and Head of Business Developments for the Energy Transfer family since June 2013. Mr. Welch has also served on the Board of Directors of ETE, ETP, and Sunoco

Logistics since June 2013. Before joining ETE, Mr. Welch was Head of the EMEA Investment Banking Department and Head of the Global Energy Group at Credit Suisse. He was also a member of the IBD Global Management Committee and the EMEA Operating Committee. Mr. Welch joined Credit Suisse First Boston in 1997 from Lehman Brothers Inc. in New York, where he was a Senior Vice President in the

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global utilities & project finance group. Prior to that he was an attorney with Milbank, Tweed, Hadley & McCloy (New York) and a barrister and solicitor with Minter Ellison in Melbourne, Australia. The members of our General Partner selected Mr. Welch to serve on the Board of Directors because of his understanding of energy-related corporate finance gained through his experience in the investment banking and legal fields.

Thomas P. Mason. Mr. Mason has served as Senior Vice President, General Counsel and Secretary of our General Partner since April 2012. Mr. Mason previously served as Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary of our General Partner from February 2007. Prior to joining ETP, he was a partner in the Houston office of Vinson & Elkins. Mr. Mason has specialized in securities offerings and mergers and acquisitions for more than 25 years. Mr. Mason also serves on the Board of Directors of the general partner of Sunoco Logistics.

Richard Cargile. Mr. Cargile joined ETP in March 2012 and serves as President of Midstream Operations. Mr. Cargile joined ETP with over 30 years of midstream experience. Mr. Cargile joined Phillips Petroleum Company in 1982 as a project development engineer. He worked in various capacities in the gas and gas liquids group of Phillips Petroleum Company, Phillips 66 Natural Gas Company and GPM Gas Corporation. He was named vice president of East Permian Commercial in 2000 when GPM Gas Corporation merged with DCP Midstream, LLC ("DCP"). In 2003, he rose to Southern Division Vice President where he was responsible for DCP's Permian and Gulf Coast business units and appointed to DCP's Executive Committee. In 2007, he was promoted to Group Vice President of commercial and business development, and in 2008 he was named Group Vice President of EHS, operations, and technical services. In 2009, he was appointed to president of DCP's southern business unit, where his responsibilities included executive management of commercial and operations of assets in the west and east regions, and was responsible for corporate engineering, technical services, measurement and reliability.

Paul E. Glaske. Mr. Glaske retired as Chairman and Chief Executive Officer of Blue Bird Corporation, the largest manufacturer of school buses with manufacturing plants in three countries. Prior to becoming president of Blue Bird in 1986, Mr. Glaske served as the president of the Marathon LeTourneau Company, a manufacturer of large off-road mining and material handling equipment and off-shore drilling rigs. He served as a member of the board of directors of BorgWarner, Inc. of Chicago, Illinois until April 2008. Currently, Mr. Glaske serves on the board of directors of both Lincoln Educational Services in New Jersey, and Camcraft, Inc., in Illinois. Mr. Glaske has served as a director of our General Partner since February 2004 and is chairman of the Audit Committee. The Board selected Mr. Glaske to serve as a director because it believes he is familiar with running a company from the field level to the boardroom based on his previous experience. As a former CEO and director at various other companies, Mr. Glaske has been involved in succession planning, compensation, employee management and the evaluation of acquisition opportunities.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. He also serves as a Director to both Oasis Petroleum Corp. and CLL Global Research Foundation. He has also served on both the Audit Committee and Nominating and Governance Committee for Oasis Petroleum Corp. since May of 2011. Mr. Collins previously served as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988 Mr. Collins was President of Enron Oil & Gas Co. and its predecessors, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quasar Petroleum Company. Mr. Collins has served as a director of our General Partner since August 2004. Mr. Collins is a past President of the Permian Basin Petroleum Association; the Permian Basin Landmen's Association, the Petroleum Club of Midland and has served as Chairman of the Midland Wildcat Committee since 1984. The Board selected Mr. Collins to serve as a director because of his previous experience as an executive in various positions in the oil and gas industry. In addition, as a public company director at various other companies, Mr. Collins has been involved in succession planning, compensation, employee management and the evaluation of acquisition properties.

Michael K. Grimm. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and served as its President and Chief Executive Officer from 1995 until 2006 when it was sold. Currently, Mr. Grimm is President of Rising Star Energy Development Company, Rising Star Petroleum, LLC and is Chairman of the Board of RSP Permian, which is active in the drilling and developing of West Texas Permian Basin oil reserves. Prior to the formation of the first

Rising Star companies, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for 13 years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Dallas Wildcat Committee, and Fort Worth Wildcatters. Mr. Grimm has served as a director of our General Partner since December 2005 and is a member of the Audit Committee and chairman of the Compensation Committee. He has a B.B.A. from the University of Texas at Austin. The Board selected Mr. Grimm to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

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David K. Skidmore. Mr. Skidmore has served as a director of our General Partner since March 2013. He has been Vice President of Ventex Oil & Gas, Inc. since 1995 and has been actively involved in exploration and production throughout the Gulf Coast and mid-Continent regions for over 35 years. He founded Skidmore Exploration, Inc. in 1981 and has been an independent oil and gas producer since that time. From 1977 to 1981, he worked for Paraffine Oil Corporation and Texas Oil & Gas in Houston. He holds BS degrees in both Geology and Petroleum Engineering, is a Certified Petroleum Geologist and Registered Professional Engineer, and active member of the AAPG, and SPE. Mr. Skidmore is a member of both the Audit Committee and Compensation Committee. The Board selected Mr. Skidmore to serve as a director because of his continual involvement in geological, geophysical, legal, engineering and accounting aspects of an active oil and gas exploration and production company. As an energy professional, active oil and gas producer and successful business owner, Mr. Skidmore possesses valuable first-hand knowledge of the energy transportation business and market conditions affecting its economics.

Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Companies. Our General Partner and its affiliates performing services for the Partnership and the Operating Companies are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to, but not paid directly by, the Partnership, if any, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Our employees are employed by our Operating Companies, and thus, our General Partner does not incur additional reimbursable costs.

Our General Partner is ultimately controlled by the general partner of ETE, which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our Partnership Agreement with respect to its ownership of a general partner interest and the incentive distribution rights specified in our Partnership Agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our Partnership Agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner’s executive officers. Our General Partner’s distribution rights are described in detail in Note 7 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

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

Based solely on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during the year ended December 31, 2013, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, with the exception of a late filing of a Form 4 transaction by Mr. Warren.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner, which in turn is managed by its general partner, ETP LLC, which we refer to in this Item as “our General Partner.” As of December 31, 2013, ETE owned 100% of our General Partner, approximately 14.8% of our outstanding Common Units and 100% of our outstanding Class H Units. All of our employees are employed by and receive employee benefits from our Operating Companies.

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Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of our management functions. As a result, the executive officers of our General Partner are essentially our executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The executive officers we refer to in this discussion as our "named executive officers" are the following officers of our General Partner:

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

Our General Partner's Philosophy for Compensation of Executives

In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based or "at-risk" compensation and that executives' total compensation levels should be very competitive in the marketplace for executive talent and abilities. Our General Partner seeks a total compensation program that provides for a slightly below the median market annual base compensation rate but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market.

Our General Partner believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of our named executive officers to the success of the Partnership and the achievement of the annual financial performance objectives and (ii) the annual grant of restricted unit awards under our equity incentive plan(s), which awards are intended to provide a longer term incentive and retention value to our key employees to focus their efforts on increasing the market price of our publicly traded units and to increase the cash distribution we pay to our Unitholders.

Prior to December 2012, our equity awards were primarily in the form of restricted unit awards that vest over a specified time period, with substantially all of these awards vesting over a five-year period at 20% per year based on continued employment through each specified vesting date. Beginning in December 2012, we began granting restricted unit awards that vest, based upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. Our General Partner believes that these equity-based incentive arrangements are important in attracting and retaining our executive officers and key employees as well as motivating these individuals to achieve our business objectives. The equity-based compensation also reflects the importance we place on aligning the interests of our named executive officers with those of our Unitholders.

While we are responsible for the direct payment of the compensation of our named executive officers as employees of ETP, ETP does not participate or have any input in any decisions as to the compensation policies of our General Partner or the compensation levels of the executive officers of our General Partner. The compensation committee of the board of directors of our General Partner (the "Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of these executive officers. We directly pay these executive officers in lieu of receiving an allocation of overhead related to executive compensation from our General Partner. For the year ended December 31, 2013, we paid 100% of the compensation of the executive officers of our General Partner as we represent the only business currently managed by our General Partner.

For a more detailed description of the compensation of our named executive officers, please see "Compensation Tables" below.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- reward executives with an industry-competitive total compensation package of competitive base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;

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- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based or "at-risk" compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2013, the compensation paid to our named executive officers, other than our CEO, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- time-vested restricted unit awards under the equity incentive plan(s);
- payment of distribution equivalent rights ("DERs") on unvested time-based restricted unit awards under our equity incentive plan;
- vesting of previously issued time-based awards issued pursuant to our equity incentive plans;
- compensation resulting from the vesting of equity issuances made by an affiliate; and
- 401(k) plan employer contributions.

Mr. Warren, our CEO, has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits).

Methodology

The Compensation Committee considers relevant data available to it to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The Compensation Committee also considers individual performance, levels of responsibility, skills and experience. Periodically, the Compensation Committee engages a third-party consultant to provide market information for compensation levels at peer companies in order to assist the Compensation Committee in its determination of compensation levels for our executive officers. Most recently, the Compensation Committee engaged Mercer (US) Inc. ("Mercer") during the year ended December 31, 2013 to both (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including our named executive officers; (ii) assist in the determination of appropriate compensation levels for our senior management, including the named executive officers; and (iii) to confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy. This review by Mercer was deemed necessary given the series of transforming transactions we have completed over the past few years, which have significantly increased our size and scale from both a financial and asset perspective.

In conducting its review, Mercer worked with us to identify a "peer group" of 15 leading companies in the energy industry that most closely reflect our profile in terms of revenues, assets and market value as well as compete with us for talent at the senior management level. The identified companies were:

- Conoco Phillips
- Enterprise Products Partners, L.P.
- Plains All American Pipeline, L.P.
- Halliburton Company
- National Oilwell Varco, Inc.
- Baker Hughes Incorporated
- Apache Corp.
- Marathon Oil Corporation
- Anadarko Petroleum
- ONEOK Partners, L.P.
- EOG Resources, Inc.
- Kinder Morgan Energy Partners, L.P.
- The Williams Companies, Inc.
- Enbridge Energy Partners, L.P.
- DCP Midstream Partners, L.P.

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The compensation analysis provided by Mercer covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives of these companies. The Compensation Committee utilized the information provided by Mercer to compare the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at these other companies with those of our named executive officers to ensure that compensation of our named executive officers is both consistent with our compensation philosophy and competitive with the compensation for executive officers of these other companies. The Compensation Committee considered and reviewed the results of the study performed by Mercer to ensure the results indicated that our compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives. The Compensation Committee also specifically evaluated benchmarked results for the annual base salary, annual short-term cash bonus or long-term equity incentive awards of the named executive officers to the compensation levels at the identified “peer group” companies. Mercer did not provide any non-executive compensation services for the Partnership during 2013.

Base Salary. As discussed above, the base salaries of our named executive officers are targeted to yield an annual base salary slightly below the median level of market and are determined by the Compensation Committee after taking into account the recommendations of Mr. Warren. For 2013, the Compensation Committee approved an increase of 6.7% to Mr. McCrea’s annual base salary, 5.9% to Mr. Salinas’ annual base salary, and 10% to Mr. Mason’s annual base salary. The Compensation Committee determined that such increases were warranted based on the results of the Mercer study and the factors described below under “Annual Bonus.” The Compensation Committee also deemed the increases to be reasonable in light of the expanded roles that each of the individuals serves with respect to the consolidated organization subsequent to the Citrus, Sunoco and Holdco Transactions in 2012 and the associated increased in role and responsibility of each named executive office in light of the same.

Annual Bonus. In addition to base salary, the Compensation Committee makes a determination whether to award our named executive officers, other than our CEO (who has voluntarily elected to forgo any annual bonuses), discretionary annual cash bonuses following the end of the year. These discretionary bonuses, if awarded, are intended to reward our named executive officers for the achievement of financial performance objectives during the year for which the bonuses are awarded in light of the contribution of each individual to our profitability and success during such year. In this regard, the Compensation Committee takes into account whether the Partnership achieved or exceeded its internal EBITDA budget for the year, which is approved by the board of directors of our General Partner as discussed below, as an important element in making its determinations with respect to annual bonuses. The Compensation Committee also considers the recommendation of our CEO in determining the specific annual cash bonus amounts for each of the other named executive officers. The Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and the Compensation Committee does not utilize any formulaic approach to determine annual bonuses.

The Partnership’s internal financial budgets are generally developed for each business segment, and then aggregated with appropriate corporate level adjustments, to reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all segments of the Partnership’s business. The evaluation of the Partnership’s performance versus its internal financial budget is based on the Partnership’s EBITDA for a calendar year. In general, the Compensation Committee believes that Partnership performance at or above the internal EBITDA budget would support bonuses to our named executive officers ranging from 100% to 140% of their annual bonus target. For 2013, the Compensation Committee approved a short-term annual cash bonus target for Mr. McCrea of 140% of his annual base salary, 120% of his annual base salary for Mr. Salinas, 125% of his annual base salary for Mr. Mason and 100% of his annual base salary for Mr. Cargile. In the cases of Messrs. McCrea, Salinas and Mason their annual bonus target was increased to its new level from a target of 100% of annual base salary consistent with the results of the Mercer study, while Mr. Cargile’s target remained at its 2012 level of 100% of annual base salary. In February 2014, the Compensation Committee approved cash bonuses relating to the 2013 calendar year to Messrs. McCrea, Salinas, Mason and Cargile of $1,080,961, $524,423, $646,635 and $305,000, respectively. The individual bonus amounts for each named executive officer, other than our CEO, also reflect the Compensation Committee’s view of the impact of such individual’s efforts and contributions towards

(i) achievement of the Partnership's success in exceeding its internal financial budget, (ii) the development of new projects that are expected to result in increased cash flows from operations in future years, (iii) the completion of mergers, acquisitions or similar transactions that are expected to be accretive to the Partnership and increase distributable cash flow, (iv) the overall management of the Partnership's business, and (v) the individual performances of these individuals with respect to promoting the Partnership's financial, strategic and operating objectives for 2013. The cash bonuses awarded to each of the executive officers for 2013 were consistent with the target.

Equity Awards. Each of our 2004 Unit Plan and 2008 Incentive Plan authorizes the Compensation Committee, in its discretion, to grant awards of restricted units, phantom units, unit options and other awards related to our units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by each such plan. The Compensation Committee determined and/or approved the terms of the unit grants awarded to our named executive officers, including the number of Common Units subject to the unit award and the vesting structure of those unit awards. All of the awards granted to the named executive officers under these equity incentive plans have consisted of restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any unit award, ETP Common Units are issued.

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In consideration of the results of the Mercer study for 2013, the Compensation Committee approved increased long-term incentive awards targets for certain of the named executive officers. Mr. McCrea's long-term incentive target increased from 330% of his annual base salary to 700% of his base salary, Mr. Salinas' annual long-term incentive target increased from 250% of his annual base salary to 300%, Mr. Mason's annual long-term incentive target increased from 270% of his annual base salary to 400% and Mr. Cargile's target remained at 150% of annual base salary. In December 2013, the Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas, Mason and Cargile of 69,375 units, 16,724 units, 40,923 units and 9,500 units, respectively. These unit awards provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, subject to continued employment through each specified vesting date. As described below in the section titled Subsidiary Equity Awards, for 2013, in discussions between the Compensation Committee and the CEO as well as the compensation committee of the general partner of Sunoco Logistics, it was determined that approximately 33% of the total long-term incentive award target values of Messrs. McCrea and Salinas would be composed of restricted units awarded under Sunoco Logistics' equity incentive plan in considerations for their roles and responsibilities at Sunoco Logistics in addition to the Partnership. At Sunoco Logistics, Mr. McCrea serves as Chairman of the Board of Sunoco Logistics' general partner and Mr. Salinas serves as a member of the board and Chief Financial Officer of Sunoco Logistics' general partner. It is expected that the long-term equity awards of Messrs. McCrea and Salinas will recognize a similar aggregation of restricted units being awarded under our equity incentive plan and Sunoco Logistics' equity incentive plan in future years. The terms and conditions of the restricted unit awards to Messrs. McCrea and Salinas under the Sunoco Logistics equity plan are identical to the terms and conditions of the restricted unit awards under our equity plan to Messrs. McCrea and Salinas.

These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a DER cash payment promptly following each such distribution by us to our Unitholders. In approving the grant of such unit awards, the Compensation Committee took into account the same factors as discussed above under the caption "Annual Bonus," the long-term objective of retaining such individuals as key drivers of the Partnership's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity unit awards subject to vesting.

The issuance of Common Units pursuant to our equity incentive plans is intended to serve as a means of incentive compensation; therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

The unit awards under our equity incentive plans generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of a change in control of the Partnership or the death or disability of the award recipient prior to the applicable vesting period being satisfied. The Compensation Committee has in the past and may in the future, but is not required to, accelerate the vesting of unvested unit awards in the event of the termination or retirement of an executive officer. The Compensation Committee did not accelerate the vesting of unit awards to any named executive officers in 2013.

Unit Ownership Guidelines. In December 2013, the Board of Directors adopted the ETP Executive Unit Ownership Guidelines (the "Guidelines"), which set forth minimum ownership guidelines applicable to certain executives of the Partnership with respect to Common Units representing limited partnership interests in the Partnership. The applicable unit ownership guidelines are denominated as a multiple of base salary, and the amount of Common Units required to be owned increases with the level of responsibility. Under these guidelines, the President and Chief Operating Officer is expected to own Common Units having a minimum value of five times his base salary, while each of the remaining named executive officers (other than our CEO) are expected to own Common Units having a minimum value of four times their respective base salary. In addition to the named executive officers, these guidelines also apply to other covered executives, which executives are expected to own either directly or indirectly in accordance with the terms of the Guidelines Common Units having minimum values ranging from two to four times their respective base salary. The Guidelines do not apply to our CEO, who receives a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits.

Our General Partner and the Compensation Committee believe that the ownership of our Common Units, as reflected in the Guidelines, is an important means of tying the financial risks and rewards for our executives to our total

unitholder return, aligning the interests of such executives with those of our Unitholders, and promoting the Partnership's interest in good corporate governance.
Covered executives are generally required to achieve their ownership level within five years of becoming subject to the guidelines; however, certain covered executives, based on their tenure as an executive, are required to achieve compliance within two years of the December 2013 effective date of the Guidelines. Thus, compliance with the guidelines will be required for all of our current named executive officers beginning December 2015, except for Richard Cargile who joined ETP in March 2012.
Covered executives may satisfy the guidelines through direct ownership of Common Units or indirect ownership by certain immediate family members. Direct or indirect ownership of ETE common units shall count on a one to one ratio for purposes of

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satisfying minimum ownership requirements; however, unvested unit awards may not be used to satisfy the minimum ownership requirements.

Executive officers who have not yet met their respective guideline must retain and hold all Common Units (less Common Units sold to cover the executive's applicable taxes and withholding obligation) received in connection with long-term incentive awards. Once the required ownership level is achieved, ownership of the required Common Units must be maintained for as long as the covered executive is subject to the guidelines. However, those individuals who have met or exceeded their applicable ownership guideline may dispose of our Common Units in a manner consistent with applicable laws, rules and regulations, including regulations of the SEC and our internal policies, but only to the extent that such individual's remaining ownership of Common Units would continue to exceed the applicable ownership guideline.

Subsidiary Equity Awards. In addition to their roles as officers of our General Partner, Messrs. McCrea and Salinas also serve as officers and directors of the general partner of Sunoco Logistics. In connection with those roles at Sunoco Logistics' general partner, in December 2013, the compensation committee of Sunoco Logistics' general partner awarded Messrs. McCrea and Salinas time-based restricted units of Sunoco Logistics in the amount of 27,300 units and 6,550 units, respectively. The terms and conditions of the restricted unit awards to Messrs. McCrea and Salinas under the Sunoco Logistics equity plan are identical to the terms and conditions of the restricted unit awards under our equity plan to Messrs. McCrea and Salinas.

The previous annual grant of Sunoco Logistics equity awards occurred in January 2013, at which time Messrs. McCrea and Salinas were granted 16,667 units and 8,333 units, respectively. These awards are reflected as compensation in 2013 for Messrs. McCrea and Salinas in the "Compensation Tables" section below.

Affiliate Equity Awards. McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of ETE's general partner, has previously awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officers. These rights included the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the officer vested in the ETE units at a rate of 20% per year. As these ETE units conveyed to the recipients of the awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards were paid by ETE or ETP. We recognized non-cash compensation expense over the vesting period based on the grant date fair value of the ETE units awarded the ETP employees assuming no forfeitures. As of December 31, 2013, no such affiliate equity awards remained outstanding. During 2013, Messrs. McCrea and Salinas vested in rights related to ETE units of 84,000 and 96,000, respectively (after adjustment for ETE's two-for-one common unit split in January 2014).

Qualified Retirement Plan Benefits. We have established a defined contribution 401(k) plan, which covers substantially all of our employees, including our named executive officers. Employees may elect to defer up to 100% of their eligible compensation after applicable taxes, as limited under the Internal Revenue Code. We make a matching contribution that is not less than the aggregate amount of matching contributions that would be credited to a participant's account based on a rate of match equal to 100% of each participant's elective deferrals up to 5% of covered compensation. The amounts deferred by the participant and the amounts deferred by the Partnership are fully vested at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

Beginning in January 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with a base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Health and Welfare Benefits. All full-time employees, including our named executive officers, may participate in our health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance and disability insurance.

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner. Our 2004 Unit Plan provides for immediate vesting of all unvested unit awards in the event of a change in control, as defined in the plan. In addition, our 2008 Incentive Plan provides the Compensation Committee with the discretion to provide for immediate vesting of all unvested unit awards in the event of a change of control, as defined in the plan. Please refer to “Compensation Tables – Potential Payments Upon a Termination or Change of Control” for additional information.

In addition, our General Partner has also adopted the ETP GP Severance Plan and Summary Plan Description effective as of June 12, 2013, (the “Severance Plan”), which provides for payment of certain severance benefits in the event of Qualifying Termination (as that term is defined in the Severance Plan). In general, the Severance Plan provides payment of two weeks of annual base salary for each year or partial year of employment service with the Partnership up to a maximum of fifty-two weeks or one year of annual base salary (with a minimum of four weeks of annual base salary) and up to three months of continued group health insurance coverage. The Severance Plan also provides that the Partnership may determine to pay benefits in addition to those provided under the Severance Plan based on special circumstances, which additional benefits shall be unique and nonprecedent setting. The Severance Plan is available to all salaried employees on a nondiscriminatory basis; therefore, amounts that would be payable to our named executive officers upon a Qualified Termination have been excluded from “Compensation Tables – Potential Payments Upon a Termination or Change of Control” below.

Deferred Compensation Plan. We maintain a deferred compensation plan (“DC Plan”), which permits eligible highly compensated employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other designated distribution. Under the DC Plan, each year eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, ETP may make annual discretionary matching contributions to participants’ accounts; however, we have not made any discretionary contributions to participants’ accounts and currently have no plans to make any discretionary contributions to participants’ accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings (or losses) based on hypothetical investment fund choices made by the participants among available funds.

Participants may elect to have their accounts distributed in one lump sum payment or in annual installments over a period of three or five years upon retirement, and in a lump sum upon other termination. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. Upon a change in control (as defined in the DC Plan) of ETP, all DC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the DC Plan’s normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement.

Risk Assessment Related to our Compensation Structure. We believe our compensation plans and programs for our named executive officers, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to the Partnership. We believe our compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm our value or reward poor judgment. We also believe we have allocated our compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for the executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment. We generally determine whether, and to what extent, our named executive officers receive a cash bonus based on our achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership’s success. We use restricted units rather than unit options for equity awards because restricted units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options “in-the-money.” Finally, the time-based vesting over five years for our long-term incentive awards ensures that our employees’ interests align with those of our Unitholders for the long-term performance of the Partnership.

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

For our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 8 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm and Skidmore served on the Compensation Committee during 2013. During 2013, none of the members of the committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company’s board of directors. In addition, neither Mr. Grimm nor Mr. Skidmore are former employees of ours or any of our subsidiaries.

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Report of Compensation Committee

The Compensation Committee of the board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of ETP. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the
Board of Directors of Energy Transfer Partners, L.L.C., the
general partner of the Energy Transfer Partners GP, L.P., the
general partner of Energy Transfer Partners, L.P.
Michael K. Grimm
David K. Skidmore

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

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Compensation Tables
Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus[1] ($)	Equity Awards[2] ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation[3] ($)	Total ($)
Kelcy L. Warren[4]	2013	$5,814	$—	$—	$—	$ —	$ —	$ —	$5,814
Chief Executive	2012	3,700	—	—	—	—	—	—	3,700
Officer	2011	3,240	—	—	—	—	—	—	3,240
Martin Salinas, Jr.	2013	437,019	524,423	1,861,698	—	—	56,036	26,136	2,905,312
Chief Financial	2012	392,750	375,000	755,515	—	—	23,261	26,140	1,572,666
Officer	2011	360,532	400,000	1,128,500	—	—	(6,462)	25,020	1,907,590
Marshall S. (Mackie) McCrea, III	2013	772,115	1,080,961	6,715,336	—	—	—	13,323	8,581,735
President and Chief	2012	690,000	700,000	1,510,985	—	—	—	12,802	2,913,787
Operating Officer	2011	615,049	750,000	9,542,520	—	—	—	12,972	10,920,541
Thomas P. Mason	2013	517,308	646,635	2,308,057	—	—	—	36,923	3,508,923
Senior Vice President, General	2012	466,424	500,000	1,359,900	—	—	—	35,998	2,362,322
Counsel and Secretary	2011	432,901	750,000	1,805,600	—	—	—	32,590	3,021,091
Richard Cargile	2013	331,250	305,000	535,800	—	—	83,943	13,323	1,269,316
President of Midstream Operations	2012	237,500	230,000	1,379,880	—	—	3,534	12,279	1,863,193

(1) The discretionary cash bonus amounts for our named executive officers for 2013 reflect cash bonuses approved by the Compensation Committee in February 2014 that are expected to be paid in March 2014.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. See Note 8 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2013 in this column include (i) matching contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $9,327 for Mr. Salinas and $12,750 each for Messrs. McCrea, Mason and Cargile, (ii) expenses paid by us for housing for Messrs. Salinas and Mason near our executive office in Dallas and (iii) the dollar value of life insurance premiums paid for the benefit of the named executive officers. Vesting in 401(k) contributions occurs immediately.

(4) Mr. Warren voluntarily determined that his salary would be reduced to $1.00 per year (plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits). He does not accept a cash bonus or any equity awards under the equity incentive plans.

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Grants of Plan-Based Awards Table

Name	Grant Date	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Unit)	Grant Date Fair Value of Unit Awards[1]
ETP Unit Awards:					
Kelcy L. Warren	N/A	—	—	$—	$—
Martin Salinas, Jr.	12/30/2013	16,724	—	—	943,234
Marshall S. (Mackie) McCrea, III	12/30/2013	69,375	—	—	3,912,750
Thomas P. Mason	12/30/2013	40,923	—	—	2,308,057
Richard Cargile	12/30/2013	9,500	—	—	535,800
Sunoco Logistics Unit Awards:					
Martin Salinas, Jr.	12/05/2013	6,550	—	—	445,400
	1/24/2013	8,333	—	—	473,064
Marshall S. (Mackie) McCrea, III	12/05/2013	27,300	—	—	1,856,400
	1/24/2013	16,667	—	—	946,186

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 8 to our consolidated financial statements.

Narrative Disclosure to Summary Compensation Table and Grants of the Plan-Based Awards Table

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, nonqualified deferred compensation earnings, and 401(k) plan contributions can be found in the compensation discussion and analysis that precedes these tables.

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Outstanding Equity Awards at Year-End Table

Name	Grant Date[1]	Unit Awards Equity Incentive Plan Awards: Number of Units That Have Not Vested[1] (#)	Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested[2] ($)
ETP Unit Awards:			
Kelcy L. Warren	N/A	—	$—
Martin Salinas, Jr.	12/30/2013	16,724	957,449
	1/10/2013	16,667	954,186
	12/20/2011	15,000	858,750
	12/15/2010	8,000	458,000
	12/15/2009	3,837	219,668
Marshall S. (Mackie) McCrea, III	12/30/2013	69,375	3,971,719
	1/10/2013	33,333	1,908,314
	12/20/2011	30,000	1,717,500
	5/2/2011	54,400	3,114,400
	1/14/2011	100,000	5,725,000
	12/15/2009	4,000	229,000
Thomas P. Mason	12/30/2013	40,923	2,342,842
	1/10/2013	30,000	1,717,500
	12/20/2011	24,000	1,374,000
	12/15/2010	8,000	458,000
	12/15/2009	3,637	208,218
Richard Cargile	12/30/2013	9,500	543,875
	1/10/2013	12,000	687,000
	3/14/2012	10,800	618,300
Sunoco Logistics Unit Awards:			
Martin Salinas, Jr.	12/5/2013	6,550	494,394
	1/24/2013	6,666	503,150
Marshall S. (Mackie) McCrea, III	12/5/2013	27,300	2,060,604
	1/24/2013	13,333	1,006,375

(1) ETP Common Unit awards outstanding to Messrs. Salinas, McCrea, Mason and Cargile vest as follows:

- at a rate of 60% in December 2016 and 40% in December 2018 for awards granted in December 2013;
- at a rate of 60% in December 2015 and 40% in December 2017 for awards granted in January 2013;
- ratably in December of each year through 2016 for awards granted in December 2011 and March 2012;
- ratably in December of each year through 2015 for awards granted in December 2010, January 2011 and May 2011; and
- in December 2014 for awards granted in December 2009.

Sunoco Logistics common unit awards outstanding to Messrs. Salinas and McCrea vest as follows:

- ratably in December of each year through 2018 for awards granted in December 2013; and
- ratably in December of each year through 2017 for awards granted in January 2013.

(2) Market value was computed as the number of unvested awards as of December 31, 2013 multiplied by the closing price of our Common Units or Sunoco Logistics common units, accordingly, on December 31, 2013.

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Option Exercises and Units Vested Table

Name	Unit Awards Number of Units Acquired on Vesting[(1)] (#)	Value Realized on Vesting[(1)] ($)
ETP Unit Awards:		
Kelcy L. Warren	—	$—
Martin Salinas, Jr.	16,837	908,053
Marshall S. (Mackie) McCrea, III	95,200	5,134,326
Thomas P. Mason	29,637	1,577,493
Richard Cargile	3,600	194,155
Sunoco Logistics Unit Awards:		
Martin Salinas, Jr.	1,667	114,456
Marshall S. (Mackie) McCrea, III	3,334	228,912

(1) Amounts presented represent the number of unit awards vested during 2013 and the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the closing price of our Common Units or Sunoco Logistics common units, accordingly, upon the vesting date.

We have not issued option awards.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY[(1)] ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY[(1)] ($)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE[(1)] ($)
Kelcy L. Warren	$—	$—	$—	$ —	$—
Martin Salinas, Jr.	44,610	—	56,036	—	303,495
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Richard Cargile	327,964	—	83,943	—	512,779

(1) The executive contributions and aggregate earnings reflected above for Messrs. Salinas and Cargile are included in total compensation in the “Summary Compensation Table”; the remainder of the aggregate balance at last fiscal year end was reported as compensation in previous fiscal years.

A description of the key provisions of the Partnership’s deferred compensation plan can be found in the compensation discussion and analysis above.

Potential Payments Upon a Termination or Change of Control

Equity Awards. As discussed in our Compensation Discussion and Analysis above, any unvested equity awards granted pursuant to the 2004 Unit Plan will automatically become vested upon a change of control. Assuming that a change of control occurred on December 31, 2013, the fair value of the unvested awards granted pursuant to the 2004 Unit Plan as of December 31, 2013 was $458,000 for Mr. Mason. Although any unvested equity awards granted under the 2008 Incentive Plan may also become vested upon a change of control at the discretion of the Compensation Committee, this discussion assumes a scenario in which the Compensation Committee does not exercise such discretion.

While any individual award agreement may contain a modified definition, a change in control is generally defined under the 2004 Unit Plan as the occurrence of any of the following events: (i) ETP GP ceases to be our general partner; (ii) ETE ceases to own, directly or indirectly through wholly-owned subsidiaries, in the aggregate at least 51% of the capital stock or equity interests of ETP GP; (iii) the sale of all or substantially all of ETP’s assets (other than to any affiliate of ETE); or (iv) a liquidation or dissolution of ETP. Under the 2008 Incentive Plan, a “change of control” is generally defined as the occurrence of one or more of the following events: (1) any person or group becomes the beneficial owner of 50% or more of our voting power or voting securities; (2) the complete liquidation of either

ETP LLC, ETP GP, or us; (3) the sale of all or substantially all of ETP GP's or our assets to anyone other than us, ETP GP or one of our affiliates; or (4) a person other than ETP LLC, ETP GP or one of their affiliates becomes our general partner.

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Deferred Compensation Plan. As discussed in our Compensation Discussion and Analysis above, all amounts under the DC Plan (other than discretionary credits) are immediately 100% vested. Upon a change in control (as defined in the DC Plan), distributions from the DC Plan would be made in accordance with the DC Plan's normal distribution provisions. A change in control is generally defined in the DC Plan as any change in control event within the meaning of Treasury Regulation Section 1.409A-3(i)(5).

Director Compensation

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. In 2013, non-employee directors received an annual fee of $50,000 in cash. Additionally, the Chairman of the Audit Committee receives an annual fee of $15,000 and the members of the Audit Committee receive an annual fee of $10,000. The Chairman of the Compensation Committee receives an annual fee of $7,500 and the members of the Compensation Committee receive an annual fee of $5,000. In 2013, members of the Conflicts Committee received cash payments on a to-be-determined basis for each Conflicts Committee assignment. For their service on the Conflicts Committee during 2013, Messrs. Collins, Grimm and Skidmore each received additional compensation of $10,000. Employee directors, including Messrs. Warren, McCrea and Welch, do not receive any fees for service as directors. In addition, the non-employee directors participate in our 2008 Incentive Plan. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, ETP, or a subsidiary, who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of 2,500 unvested ETP Common Units. In 2014 and beyond, non-employee directors will receive annual grants of restricted ETP Common Units equal to an aggregate of $100,000 divided by the closing price of our Common Units on the date of grant. Beginning in 2013, ETP Common Units granted to non-employee directors will vest 60% after the third year and the remaining 40% after the fifth year after the grant date. Previously, vesting was ratable over three years.

The compensation paid to the non-employee directors of our General Partner in 2013 is reflected in the following table:

Name	Fees Paid in Cash[(1)] ($)	Unit Awards[(2)] ($)	All Other Compensation ($)	Total ($)
Bill W. Byrne[(3)]	$78,995	$75,143	$—	$154,138
Paul E. Glaske	81,683	75,143	—	156,826
Ted Collins, Jr.	85,833	75,143	—	160,976
Michael K. Grimm	121,792	75,143	—	196,935
David K. Skidmore[(4)]	63,826	117,750	—	181,576

(1) Fees paid in cash are based on amounts paid during the period.

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price of Common Units as of the grant date.

(3) Mr. Byrne resigned from the Board of Directors in August 2013.

(4) Mr. Skidmore was appointed to the Board of Directors in March 2013.

As of December 31, 2013, Messrs. Glaske, Collins and Grimm each had 2,352 unit awards outstanding and Mr. Skidmore had 2,500 unit awards outstanding.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth, in tabular format, a summary of certain information related to our equity incentive plans as of December 31, 2013:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[(a)]	Weighted-average exercise price of outstanding options, warrants and rights[(b)]	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column[(a)])[(c)]
Equity compensation plans approved by security holders	3,181,165	$—	915,922
Equity compensation plans not approved by security holders	—	—	—
Total	3,181,165	—	915,922

Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 18, 2014, regarding the beneficial ownership of our securities by certain beneficial owners, each director and named executive officer of our General Partner and all directors and executive officers of our General Partner as a group. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Title of Class	Name and Address of Beneficial Owner[(1)]	Beneficially Owned[(2)(3)]	Percent of Class	
Common Units	Kelcy L. Warren	21,107	*	
	Marshall S. (Mackie) McCrea , III	206,574	*	
	Martin Salinas, Jr.	45,326	*	
	Jamie Welch	20,000	*	
	Thomas P. Mason	92,692	*	
	Richard Cargile	9,287	*	
	Paul E. Glaske	98,578	*	
	Ted Collins, Jr.	99,739	*	
	Michael K. Grimm	22,877	*	
	David K. Skidmore	1,010	*	
	All Directors and Executive Officers as a Group (10 Persons)	617,190	*	
	ETE[(4)]	44,324,102	13.2	%
	ETE Holdings[(4)]	5,226,967	1.6	%
Class E Units	Heritage Holdings, Inc.[(5)]	8,853,832	100	%
Class G Units	Sunoco, Inc.[(6)]	90,706,000	100	%
Class H Units	ETE Holdings[(4)]	50,160,000	100	%

*Less than 1%

(1) The address for Messrs. Warren, Salinas, Welch, Mason, Cargile, Glaske, Collins, Grimm and Skidmore is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Heritage Holdings is 8801 S. Yale Avenue, Suite 310, Tulsa, Oklahoma 74137. The address for Mr. McCrea is 800 E. Sonterra Blvd., San Antonio, Texas 78258. The address for ETE and ETE Holdings is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Sunoco, Inc. is 1818 Market Street, Suite 1500, Philadelphia, Pennsylvania 19103.

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(2) Beneficial ownership for the purposes of the foregoing table is defined by Rule 13d-3 under the Exchange Act. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers within sixty (60) days.

(3) Due to the ownership by certain officers and directors of the general partner of ETE of equity interests in ETE (either directly or through one or more entities) and due to their positions as directors of the general partner of ETE, they may be deemed to beneficially own the limited partnership interests held by ETE, to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

(4) ETE owns all member interests of Energy Transfer Partners, L.L.C and all of the Class A limited partner interests and Class B limited partner interests in Energy Transfer Partners GP, L.P. Energy Transfer Partners, L.L.C. is the general partner of Energy Transfer Partners GP, L.P. with a 0.01% general partner interest. LE GP, LLC, the general partner of ETE, may be deemed to beneficially own the Common Units owned of record by ETE. The members of LE GP, LLC are Ray C. Davis and Kelcy L. Warren.

(5) The Partnership indirectly owns 100% of the common stock of Heritage Holdings, Inc.

(6) The Partnership indirectly owns 100% of the common stock of Sunoco, Inc.

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For a discussion of director independence, see Item 10. “Directors, Executive Officers and Corporate Governance.”

As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership’s board of directors makes the determinations as to whether there exists a related-party transaction in the normal course of reviewing transactions for approval as the Partnership’s board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors’ approval is sought by the Partnership’s management. In addition, the Partnership’s board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership’s board makes those determinations in light of its contractually-limited fiduciary duties to the Unitholders. The Partnership Agreement provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all the partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders (see “Risks Related to Conflicts of Interest” in Item 1A. Risk Factors in this annual report).

ETE owns directly and indirectly the general partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights, 49.6 million ETP Common Units and 50.2 million Class H Units.

We have a shared services agreement in which we provide various general and administrative services for ETE. See discussion in Note 13 to our consolidated financial statements.

We have an operating lease agreement with the former owners of ETG, which we acquired in 2009. These former owners include Mr. Warren and Mr. Ray C. Davis, a former ETP board member. We pay these former owners $5 million in operating lease payments per year through 2017. With respect to the related party transaction with ETG, the Conflicts Committee of ETP met numerous times prior to the consummation of the transaction to discuss the terms of the transaction. The committee made the determination that the sale of ETG to ETP was fair and reasonable to ETP and that the terms of the operating lease between ETP and the former owners of ETG are fair and reasonable to ETP.

We received $27 million, $18 million and $17 million in management fees from ETE for the provision of various general and administrative services for ETE’s benefit for the years ended December 31, 2013, 2012 and 2011, respectively.

Immediately following the closing of the Partnership's acquisition of Sunoco, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, the Partnership contributed its interest in Sunoco to Holdco and retained a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to the Partnership in exchange for 90.7 million Class F Units representing limited partner interests in the Partnership. The Class F Units were entitled to 35% of

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the quarterly cash distribution generated by the Partnership and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current level. In April 2013, all of the outstanding Class F Units were exchanged for Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss.

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. 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.

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

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

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

In 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 totaling $180 million during the years ending December 31, 2016 through 2019.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following sets forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered:

	Years Ended December 31, 2013	2012
Audit fees[(1)]	$5,989,000	$4,448,000
Audit related fees[(2)]	682,300	25,000
Tax fees[(3)]	—	1,525
Total	$6,671,300	$4,474,525

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and services related to the audit of our internal control over financial reporting.

(2) Includes fees in 2013 for financial statement audits of subsidiary entities in connection with the contribution of SUGS from Southern Union to Regency and the sale of Southern Union's distribution operations. Includes fees in 2013 for audits of Sunoco's benefit plans. Includes fees in 2013 and 2012 in connection with the service organization control report on Southern Union's centralized data center.

(3) Includes fees related to state and local tax consultation.

Pursuant to the charter of the Audit Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP, including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee.

The Audit Committee reviews the external auditors' proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two years; and
- the rotation of the lead partner.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this Report:

(1) Financial Statements – see Index to Financial Statements appearing on page F-1.

(2) Financial Statement Schedules – None.

(3) Exhibits – see Index to Exhibits set forth on page E-1.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY TRANSFER PARTNERS, L.P.

By:	Energy Transfer Partners GP, L.P, its general partner.
By:	Energy Transfer Partners, L.L.C., its general partner
By:	/s/ Kelcy L. Warren Kelcy L. Warren Chief Executive Officer and officer duly authorized to sign on behalf of the registrant

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	February 27, 2014
/s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer (Principal Financial and Accounting Officer)	February 27, 2014
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	President, Chief Operating Officer and Director	February 27, 2014
/s/ Jamie Welch Jamie Welch	Director	February 27, 2014
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	February 27, 2014
/s/ Paul E. Glaske Paul E. Glaske	Director	February 27, 2014
/s/ Michael K. Grimm Michael K. Grimm	Director	February 27, 2014
/s/ David K. Skidmore David K. Skidmore	Director	February 27, 2014

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INDEX TO EXHIBITS

The exhibits listed on the following Exhibit Index are filed as part of this report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

Exhibit Number	Description
2.1	Purchase Agreement, dated March 22, 2011, among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC and Louis Dreyfus Highbridge Energy LLC, Energy Transfer Partners, L.P. and Regency Energy Partners LP. (incorporated by reference to Exhibit 2.1 to Registrant’s Form 8-K/A filed on March 25, 2011)
2.2	Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 2.1 to the Registrant’s Form 8-K filed October 18, 2011)
2.3	Amendment No. 1, dated December 1, 2011, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 2.1 to the Registrant’s Form 8-K filed December 7, 2011)
2.4	Amendment No. 2, dated January 11, 2012, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011 (incorporated by reference to Exhibit 10.1 to Exhibit 2.1 to Registrant’s Form 8-K filed on January 13, 2012)
2.5	Amendment No. 2, dated as of March 23, 2012, to the Amended and Restated Agreement and Plan of Merger, by and among Energy Transfer Partners, L.P., Citrus ETP Acquisition L.L.C., Energy Transfer Equity, L.P., Southern Union Company, and CrossCountry Energy, LLC dated July 19, 2011 (incorporated by reference to Exhibit 3.1 to Registrant’s Form 8-K filed on March 28, 2012)
2.6	Amendment No. 1, dated as of September 14, 2011, to the Amended and Restated Agreement and Plan of Merger, dated as of July19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to the Registrant’s Form 8-K filed September 15, 2011)
2.7	Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P., Citrus ETP Acquisition, L.L.C., Energy Transfer Equity, L.P. Southern Union Company and CrossCountry Energy, LLC (incorporated by reference to Exhibit 2.1 to the Registrant’s Form 8-K filed July 20, 2011)
2.8	Agreement and Plan of Merger, dated as of April 29, 2012 by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc. and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant’s Form 8-K filed on May 1, 2012)
2.9	Amendment No. 1, dated as of June 15, 2012, to the Agreement and Plan of Merger, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc., and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P. (Incorporated by reference to Exhibit 2.2 to Registrant’s Form 8-K filed on June 20, 2012)
2.10	Transaction Agreement, dated as of June 15, 2012, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage Holdings, Inc., Energy Transfer Equity, L.P., ETE Sigma Holdco, LLC and ETE Holdco Corporation (incorporated by reference to Exhibit 2.1 to Registrant’s Form 8-K filed on June 20, 2012)
3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009 (incorporated by reference to the same numbered Exhibit to the Registrant’s Form 8-K filed July 29, 2009)
3.1.1	Amendment No. 1, dated March 26, 2012, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 28, 2009 (incorporated by

	reference to Exhibit 3.1 to Registrant's Form 8-K filed on March 28, 2012)
3.1.2	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated October 5, 2012 (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed October 5, 2012)
3.1.3	Amendment No. 3, dated April 15, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K/A filed on April 18, 2013)
3.1.4	Amendment No. 4, dated April 30, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on May 1, 2013)

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Exhibit Number	Description
3.1.5	Amendment No. 5, dated October 31, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on November 1, 2013)
3.1.6	Amendment No. 6, dated February 19, 2014, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed on February 19, 2014)
3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P. (incorporated by reference as the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 29, 2004)
3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
3.5.1	Amendment No. 2, dated March 26, 2012, to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated as of April 17, 2007 (incorporated by reference to Exhibit 3.2 to Registrant's Form 8-K filed on March 28, 2012)
3.6	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed August 10, 2010)
3.6.1	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated as of August 10, 2010 (incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on March 28, 2012)
3.7	Certificate of Limited Partnership of Sunoco Logistics Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1 Registration Statement, file No. 333-71968, filed October 22, 2001)
3.8	Certificate of Limited Partnership of Sunoco Logistics Operations L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 1 to Form S-1 filed December 18, 2001)
3.9	First Amended and Restated Agreement of Limited Partnership of Sunoco Logistics Partners Operations L.P., dated as of February 8, 2002 (incorporated by reference to Exhibit 3.5 of Form 10-K, file No. 1-31219, filed April 1, 2002)
3.10	Third Amended and Restated Agreement of Limited Partnership of Sunoco Logistics Partners L.P., dated as of January 26, 2010 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-31219, filed January 28, 2010)
3.10.1	Amendment No. 1 to Third Amended and Restated Partnership Agreement of Sunoco Logistics Partners L.P., dated as of July 1, 2011 (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-31219, filed July 5, 2011)
3.10.2	Amendment No. 2 to Third Amended and Restated Partnership Agreement of Sunoco Logistics Partners L.P., dated as of November 21, 2011 (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-31219, filed November 28, 2011)
3.11	Third Amended and Restated Limited Liability Company Agreement of Sunoco Partners LLC dated as of July 1, 2011 (incorporated by reference to Exhibit 3.2 of Form 8-K, file No. 1-31219, filed July 5, 2011)
3.13	Certificate of Formation of Energy Transfer Partners, L.L.C. (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C. (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
4.1	Registration Rights Agreement, dated April 30, 2013, by and between Southern Union Company and Regency Energy Partners LP (incorporated by reference to Exhibit 4.1 to the Registrant's Form

	8-K filed on May 1, 2013)
4.2	Registration Rights Agreement, dated April 30, 2013, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on May 1, 2013)
4.3	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 3, 2006)
4.4	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005)

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Exhibit Number	Description
4.5	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on January 19, 2005)
4.6	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (Incorporated by reference to Exhibit 10.45 to the Registrant's Form 10-Q for the quarter ended February 28, 2005)
4.11	Form of Senior Indenture of Energy Transfer Partners, L.P. (incorporated by reference to the same numbered Exhibit to the Registrant's Form S-3 filed August 9, 2006)
4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P. (incorporated by reference to the same numbered Exhibit to the Registrant's Form S-3 filed August 9, 2006)
4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to the same numbered Exhibit the Registrant's Form 10-K for the year ended August 31, 2006)
4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 25, 2006)
4.15	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed March 31, 2008)
4.16	Seventh Supplemental Indenture dated December 23, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed December 23, 2008)
4.16.1	Eighth Supplemental Indenture dated April 7, 2009, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on April 7, 2009)
4.17	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed May 12, 2011)
4.18	Tenth Supplemental Indenture, dated as of January 17, 2012, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 1.1 to the Registrant's Form 8-K filed January 17, 2012)
4.19	Eleventh Supplemental Indenture dated as of January 22, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 22, 2013)
4.20	Twelfth Supplemental Indenture dated as of January 24, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed June 26, 2013)
4.21	

	Thirteenth Supplemental Indenture dated as of September 19, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed September 19, 2013)
4.22	Indenture, dated as of March 31 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 5, 2012)
4.23	First Supplemental Indenture, dated as of March 31, 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee, to the Indenture, dated as of March 31, 2009, relating to Sunoco's 9.625% Senior Notes due 2015 (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed October 5, 2012)
4.24	Second Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as trustee, to Indenture, dated as of March 31, 2009 (incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed October 5, 2012)
4.25	Indenture, dated as of June 30, 2000, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A. (incorporated by reference to Exhibit 4.4 to the Registrant's Form 8-K filed October 5, 2012)
4.26	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of June 30, 2000 (incorporated by reference to Exhibit 4.7 to the Registrant's Form 8-K filed October 5, 2012)

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Exhibit Number	Description
4.27	Indenture, dated as of May 15, 1994, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., relating to Sunoco, Inc.'s 9.00% Debentures due 2024 (incorporated by reference to Exhibit 4.8 to the Registrant's Form 8-K filed October 5, 2012)
4.28	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of May 15, 1994 (incorporated by reference to Exhibit 4.9 to the Registrant's Form 8-K filed October 5, 2012)
10.1	Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2013)
10.2	First Amendment, dated April 30, 2013, to the Services Agreement, effective as of May 26, 2010, by and among Energy Transfer Equity, L.P., ETE Services Company LLC and Regency Energy Partners LP (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
10.3	Second Amendment , dated April 30, 2013, to the Operation and Service Agreement, dated May 19, 2011, as amended, by and among La Grange Acquisition, L.P. d/b/a Energy Transfer Company, Regency Energy Partners LP, Regency GP LP and Regency Gas Services LP (incorporated by reference to Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
10.4	Guarantee of Collection, dated as of April 30, 2013, by and between Regency Energy Partners LP, PEPL Holdings, LLC and Regency Energy Finance Corp. (incorporated by reference to Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
10.5	Second Amendment, dated April 30, 2013, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010, by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.4 to the Registrant's Form 10-Q for the quarter ended June 30, 2013)
+ 10.6.6	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended June 30, 2008)
+ 10.6.7	Energy Transfer Partners Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010)
+ 10.6.8	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the 2008 Energy Transfer Partners, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 1, 2004)
+ 10.6.9	Energy Transfer Partners, L.P. Midstream Bonus Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed March 3, 2008)
10.7	Exchange and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and ETE Common Holdings, LLC dated August 7, 2013 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended September 30, 2013)
10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers, and La Grange Acquisition, L.P., as Buyer (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed February 1, 2005)
10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005)
10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC (incorporated by

	reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 18, 2006)
10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed September 18, 2006)
10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed September 18, 2006)
10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)
10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007)

Exhibit Number	Description
10.56.1	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 14, 2009)
10.57	Guarantee, dated as of March 22, 2011, by Energy Transfer Partners, L.P. in favor of Louis Dreyfus Highbridge Energy LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K/A filed on March 25, 2011)
10.58	Amended and Restated Energy Transfer Partners, L.P. Midstream Bonus Plan dated April 18, 2011 (incorporated by reference to Exhibit 10.5 to the Registrant's Form 10-Q filed on August 8, 2011)
10.59	Amended and Restated Limited Liability Company Agreement of ETP-Regency Midstream Holdings, LLC, dated May 2, 2011 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 2, 2011)
10.60	Term Loan Agreement dated as of July 28, 2011, by and among Fayetteville Express Pipeline LLC, The Royal Bank of Scotland plc, as administrative agent, and certain other agents and lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed August 2, 2011)
10.61	Amendment No. 1, dated as of September 14, 2011, to Second Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and Southern Union Company (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 15, 2011)
10.62	Second Amended and Restated Credit Agreement dated as of October 27, 2011 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and an LC Issuer, the other lenders party thereto and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc., as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 2, 2011)
10.63	First Amendment, dated as of November 19, 2013, to Second Amended and Restated Credit Agreement, dated October 27, 2011 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and an LC Issuer, the other lenders party thereto and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc., as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 20, 2013)
10.64	Guarantee of Collection made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on March 28, 2012)
10.65	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC (incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on March 28, 2012)
10.66	Capital Stock Agreement dated June 30, 1986, as amended April 3, 2000 ("Agreement"), among El Paso Energy Corporation (as successor in interest to Sonat, Inc.); CrossCountry Energy, LLC (assignee of Enron Corp., which is the successor in interest to InterNorth, Inc. by virtue of a name change and successor in interest to Houston Natural Gas Corporation by virtue of a merger) and Citrus Corp. (incorporated by reference to Exhibit 10(t) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006)
10.67	Certificate of Incorporation of Citrus Corp. (incorporated by reference to Exhibit 10(q) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006)
10.68	By-Laws of Citrus Corp. (incorporated by reference to Exhibit 10(r) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006)
10.69	Contingent Residual Support Agreement by and among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P. and, for certain limited purposes,

	UGI Corporation, dated January 12, 2012 (incorporated by reference to Exhibit 10.1 to Registrant’s Form 8-K filed on January 13, 2012)
10.70	Unitholder Agreement by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated January 12, 2012 (incorporated by reference to Exhibit 10.2 to Registrant’s Form 8-K filed on January 13, 2012)
10.71	Letter agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P, dated January 11, 2012 (incorporated by reference to Exhibit 10.3 to Registrant’s Form 8-K filed on January 13, 2012)
10.72	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 to Registrant’s Form 8-K filed on May 1, 2012)
10.73	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Missouri Acquisition, Inc. and for certain limited purposes The Laclede Group, Inc. (incorporated by reference to Exhibit 10.1 to the Registrant’s Form 8-K filed December 17, 2012)

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Exhibit Number	Description
10.74	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Massachusetts Acquisition, Inc. and for certain limited purposes, The Laclede Group, Inc. (incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K filed on December 17, 2012)
12.1*	Computation of Ratio of Earnings to Fixed Charges.
21.1*	List of Subsidiaries.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ernst & Young LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer 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.
99.1*	Report of Independent Registered Public Accounting Firm – Ernst & Young LLP opinion on consolidated financial statements of Sunoco Logistics Partners LP.
99.2	Statement of Policies Relating to Potential Conflicts among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and Regency Energy Partners LP dated as of April 26, 2011 (incorporated by reference to Exhibit 99.1 to the Registrant's Form 10-Q filed on August 8, 2011)
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2013 and December 31, 2012; (ii) our Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2013, 2012 and 2011; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011; and (vi) the notes to our Consolidated Financial Statements.

*	Filed herewith.
**	Furnished herewith.
\+	Denotes a management contract or compensatory plan or arrangement.

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INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the consolidated financial statements of Sunoco Logistics Partners L.P., a consolidated subsidiary, as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, which statements reflect total assets constituting 24 percent of consolidated total assets as of December 31, 2012, and total revenues of 20 percent of consolidated total revenues for the year then ended. Those statements were audited by other auditors, whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Sunoco Logistics Partners L.P. as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2014 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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

	December 31, 2013	2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$549	$311
Accounts receivable, net	3,359	2,910
Accounts receivable from related companies	165	94
Inventories	1,765	1,495
Exchanges receivable	56	55
Price risk management assets	35	21
Current assets held for sale	—	184
Other current assets	310	334
Total current assets	6,239	5,404
PROPERTY, PLANT AND EQUIPMENT	28,430	27,412
ACCUMULATED DEPRECIATION	(2,483)	(1,639)
	25,947	25,773
NON-CURRENT ASSETS HELD FOR SALE	—	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,436	3,502
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	17	42
GOODWILL	4,729	5,606
INTANGIBLE ASSETS, net	1,568	1,561
OTHER NON-CURRENT ASSETS, net	766	357
Total assets	$43,702	$43,230

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

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

	December 31, 2013	2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,627	$3,002
Accounts payable to related companies	45	24
Exchanges payable	285	156
Price risk management liabilities	45	110
Accrued and other current liabilities	1,428	1,562
Current maturities of long-term debt	637	609
Current liabilities held for sale	—	85
Total current liabilities	6,067	5,548
NON-CURRENT LIABILITIES HELD FOR SALE	—	142
LONG-TERM DEBT, less current maturities	16,451	15,442
LONG-TERM NOTES PAYABLE — RELATED PARTY	—	166
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	54	129
DEFERRED INCOME TAXES	3,762	3,476
OTHER NON-CURRENT LIABILITIES	1,080	995
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY:		
General Partner	171	188
Limited Partners:		
Common Unitholders (333,826,372 and 301,485,604 units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively)	9,797	9,026
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary)	—	—
Class F Unitholders (zero and 90,706,000 units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively – held by subsidiary)	—	—
Class G Unitholders (90,706,000 and zero units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively – held by subsidiary)	—	—
Class H Unitholders (50,160,000 and zero units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively)	1,511	—
Accumulated other comprehensive income (loss)	61	(13)
Total partners’ capital	11,540	9,201
Noncontrolling interest	4,748	8,131
Total equity	16,288	17,332
Total liabilities and equity	$43,702	$43,230

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

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

	Years Ended December 31,		
	2013	2012	2011
REVENUES:			
Natural gas sales	$3,165	$2,387	$2,534
NGL sales	2,817	1,718	1,113
Crude sales	15,477	2,872	—
Gathering, transportation and other fees	2,590	2,007	1,488
Refined product sales	18,479	5,299	—
Other	3,811	1,419	1,664
Total revenues	46,339	15,702	6,799
COSTS AND EXPENSES:			
Cost of products sold	41,204	12,266	4,175
Operating expenses	1,388	951	799
Depreciation and amortization	1,032	656	405
Selling, general and administrative	485	435	173
Goodwill impairment	689	—	—
Total costs and expenses	44,798	14,308	5,552
OPERATING INCOME	1,541	1,394	1,247
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(849)	(665)	(474)
Equity in earnings of unconsolidated affiliates	172	142	26
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Loss on extinguishment of debt	—	(115)	—
Gains (losses) on interest rate derivatives	44	(4)	(77)
Non-operating environmental remediation	(168)	—	—
Other, net	5	11	(3)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	832	1,820	719
Income tax expense from continuing operations	97	63	19
INCOME FROM CONTINUING OPERATIONS	735	1,757	700
Income (loss) from discontinued operations	33	(109)	(3)
NET INCOME	768	1,648	697
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	312	79	28
NET INCOME ATTRIBUTABLE TO PARTNERS	456	1,569	669
GENERAL PARTNER’S INTEREST IN NET INCOME	506	461	433
CLASS H UNITHOLDER’S INTEREST IN NET INCOME	48	—	—
LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS)	$(98)	$1,108	$236
INCOME (LOSS) FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$(0.23)	$4.93	$1.12
Diluted	$(0.23)	$4.91	$1.12
NET INCOME (LOSS) PER LIMITED PARTNER UNIT:			
Basic	$(0.18)	$4.43	$1.10
Diluted	$(0.18)	$4.42	$1.10

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)

	Years Ended December 31,		
	2013	2012	2011
Net income	$768	$1,648	$697
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(4)	(14)	(38)
Change in value of derivative instruments accounted for as cash flow hedges	(1)	8	19
Change in value of available-for-sale securities	2	—	(1)
Actuarial gain (loss) relating to pension and other postretirement benefits	66	(10)	—
Foreign currency translation adjustment	(1)	—	—
Change in other comprehensive income from equity investments	17	(9)	—
	79	(25)	(20)
Comprehensive income	847	1,623	677
Less: Comprehensive income attributable to noncontrolling interest	312	74	28
Comprehensive income attributable to partners	$535	$1,549	$649

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 EQUITY
(Dollars in millions)

		Limited Partners				
	General Partner	Common Unitholders	Class H Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2010	$175	$4,542	$—	$ 26	$ —	$4,743
Distributions to partners	(426)	(733)	—	—	—	(1,159)
Distributions to noncontrolling interest	—	—	—	—	(44)	(44)
Units issued for cash	—	1,467	—	—	—	1,467
Capital contributions from noncontrolling interest	—	—	—	—	645	645
Issuance of units in acquisitions	—	3	—	—	—	3
Other comprehensive loss, net of tax	—	—	—	(20)	—	(20)
Other, net	—	18	—	—	—	18
Net income	433	236	—	—	28	697
Balance, December 31, 2011	182	5,533	—	6	629	6,350
Distributions to partners	(454)	(889)	—	—	—	(1,343)
Distributions to noncontrolling interest	—	—	—	—	(233)	(233)
Units issued for cash	—	791	—	—	—	791
Capital contributions from noncontrolling interest	—	—	—	—	343	343
Sunoco Merger (see Note 3)	—	2,288	—	—	3,580	5,868
Holdco Transaction (see Note 3)	—	165	—	—	3,748	3,913
Issuance of units in other acquisitions (excluding Sunoco)	—	7	—	—	—	7
Other comprehensive loss net of tax	—	—	—	(19)	(6)	(25)
Other, net	(1)	23	—	—	(9)	13
Net income	461	1,108	—	—	79	1,648
Balance, December 31, 2012	188	9,026	—	(13)	8,131	17,332
Distributions to partners	(523)	(1,228)	(51)	—	—	(1,802)
Distributions to noncontrolling interest	—	—	—	—	(382)	(382)
Units issued for cash	—	1,611	—	—	—	1,611
Issuance of Class H Units (see Note 7)	—	(1,514)	1,514	—	—	—
Capital contributions from noncontrolling interest	—	—	—	—	137	137
Holdco Acquisition and SUGS Contribution (see Note 3)	—	2,013	—	(5)	(3,448)	(1,440)
Other comprehensive income, net of tax	—	—	—	79	—	79

Other, net	—	(13)	—	—	(2)	(15)
Net income (loss)	506	(98)	48	—	312	768
Balance, December 31, 2013	$171	$9,797	$1,511	$ 61	$ 4,748	$16,288

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

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

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$768	$1,648	$697
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	1,032	656	405
Deferred income taxes	48	62	4
Gain on curtailment of other postretirement benefits	—	(15)	—
Amortization included in interest expense	(80)	(35)	10
Loss on extinguishment of debt	—	115	—
LIFO valuation adjustments	(3)	75	—
Non-cash compensation expense	47	42	38
Gain on deconsolidation of Propane Business	—	(1,057)	—
Gain on sale of AmeriGas common units	(87)	—	—
Goodwill impairment	689	—	—
Write-down of assets included in loss from discontinued operations	—	132	—
Distributions on unvested awards	(12)	(8)	(8)
Equity in earnings of unconsolidated affiliates	(172)	(142)	(26)
Distributions from unconsolidated affiliates	247	132	29
Other non-cash	42	68	29
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(146)	(475)	166
Net cash provided by operating activities	2,373	1,198	1,344
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Citrus Merger	—	(1,895)	—
Cash proceeds from contribution and sale of propane operations	—	1,443	—
Cash proceeds from SUGS Contribution (See Note 3)	504	—	—
Cash paid for Holdco Acquisition (See Note 3)	(1,332)	—	—
Cash proceeds from the sale of the MGE and NEG assets (See Note 3)	1,008	—	—
Cash proceeds from the sale of AmeriGas common units	346	—	—
Cash (paid) received from all other acquisitions	(405)	531	(1,972)
Capital expenditures (excluding allowance for equity funds used during construction)	(2,575)	(2,840)	(1,416)
Contributions in aid of construction costs	52	35	25
Contributions to unconsolidated affiliates	(1)	(30)	(222)
Distributions from unconsolidated affiliates in excess of cumulative earnings	217	130	22
Proceeds from sale of disposal group	—	207	—
Proceeds from the sale of assets	53	18	9
Restricted cash	(348)	5	—
Other	21	111	1
Net cash used in investing activities	(2,460)	(2,285)	(3,553)

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

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CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	8,001	8,208	6,594
Repayments of long-term debt	(7,016)	(6,598)	(5,217)
Proceeds from borrowings from affiliates	—	221	—
Repayments of borrowings from affiliates	(166)	(55)	—
Net proceeds from issuance of Limited Partner units	1,611	791	1,467
Capital contributions received from noncontrolling interest	147	320	645
Distributions to partners	(1,802)	(1,343)	(1,159)
Distributions to noncontrolling interest	(382)	(233)	(44)
Debt issuance costs	(32)	(20)	(20)
Other	(36)	—	—
Net cash provided by financing activities	325	1,291	2,266
INCREASE IN CASH AND CASH EQUIVALENTS	238	204	57
CASH AND CASH EQUIVALENTS, beginning of period	311	107	50
CASH AND CASH EQUIVALENTS, end of period	$549	$311	$107

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)

1. OPERATIONS AND ORGANIZATION:

The consolidated financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries (the "Partnership," "we" or "ETP") presented herein for the years ended December 31, 2013, 2012 and 2011, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and subsidiaries we control, even if we do not have a majority ownership. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through the date the financial statements were issued.

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

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

In accordance with GAAP, we have accounted for the Holdco Transaction (described in Note 3), whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union). This change only impacted interim periods in 2012, and no prior annual amounts have been adjusted.

We are managed by our 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 and also owns a convenience store operator with approximately 300 company-owned and dealer locations.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
-

ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.

- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.

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- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products and crude oil pipelines, terminalling and storage assets, and refined products and crude oil acquisition and marketing assets.
- Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco. As discussed in Note 3, ETP acquired ETE’s 60% interest in Holdco on April 30, 2013. Panhandle and Sunoco operations are described as follows:
- Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation, storage and distribution of natural gas in the United States. As discussed in Note 3, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interests in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. Also, as discussed in Note 3, Southern Union completed its sale of the assets of MGE and NEG in 2013. Additionally, as discussed in Note 3, in January 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle surviving the merger.
- Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States.

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.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream, NGL and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

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

Revenue Recognition

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

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

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

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

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

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

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

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

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

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are

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not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

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

Regulatory Accounting – Regulatory Assets and Liabilities

Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for these entities, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

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

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

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

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

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

	Years Ended December 31,		
	2013	2012	2011
Accounts receivable	$(458)	$300	$3
Accounts receivable from related companies	(17)	(50)	(28)
Inventories	(256)	(253)	68
Exchanges receivable	(24)	11	3
Other current assets	(56)	571	(62)
Other non-current assets, net	(22)	(53)	7
Accounts payable	525	(979)	31
Accounts payable to related companies	(122)	100	6
Exchanges payable	131	—	3
Accrued and other current liabilities	152	(151)	60
Other non-current liabilities	151	25	—
Price risk management assets and liabilities, net	(150)	4	75
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$(146)	$(475)	$166

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

	Years Ended December 31,		
	2013	2012	2011
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$167	$359	$202
AmeriGas limited partner interest received in exchange for contribution of Propane Business	$—	$1,123	$—
Regency common and Class F units received in exchange for contribution of SUGS	$961	$—	$—
NON-CASH FINANCING ACTIVITIES:			
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$—	$6,658	$4
Issuance of Common Units in connection with acquisitions	$—	$2,295	$3
Issuance of Common Units in connection with the Holdco Acquisition	$2,464	$—	$—
Issuance of Class H Units	$1,514	$—	$—
Contributions receivable related to noncontrolling interest	$13	$23	$—
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$903	$678	$476
Cash paid for income taxes	$57	$22	$24

Accounts Receivable

Our midstream, NGL and intrastate transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible.

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Our investment in Sunoco Logistics segment extends credit terms to certain customers after review of various credit indicators, including the customer's credit rating. Outstanding customer receivable balances are regularly reviewed for possible non-payment indicators and reserves are recorded for doubtful accounts based upon management's estimate of collectability at the time of review. Actual balances are charged against the reserve when all collection efforts have been exhausted.

Our interstate transportation and storage operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Our interstate transportation and storage operations establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and consider many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

Our retail marketing segment extends credit to customers after a review of credit rating and other credit indicators. Management records reserves for bad debt by computing a proportion of average write-off activity over the past five years in comparison to the outstanding balance in accounts receivable. This proportion is then applied to the accounts receivable balance at the end of the reporting period to calculate a current estimate of what is uncollectible. The credit department and business line managers make the decision to write off an account, based on understanding of the potential collectability.

We enter into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

Inventories

Inventories consist principally of natural gas held in storage, crude oil, petroleum and chemical products. Natural gas held in storage is valued at the lower of cost or market utilizing the weighted-average cost method. The cost of crude oil and petroleum and chemical products is determined using the last-in, first out method. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31,	
	2013	2012
Natural gas and NGLs	$519	$334
Crude oil	488	418
Refined products	597	572
Appliances, parts and fittings, and other	161	171
Total inventories	$1,765	$1,495

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

Exchanges

Exchanges consist of natural gas and NGL delivery imbalances (over and under deliveries) with others. These amounts, which are valued at market prices or weighted average market prices pursuant to contractual imbalance agreements, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. These imbalances are generally settled by deliveries of natural gas or NGLs, but may be settled in cash, depending on contractual terms.

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Other Current Assets

Other current assets consisted of the following:

	December 31, 2013	2012
Deposits paid to vendors	$49	$41
Prepaid and other	261	293
Total other current assets	$310	$334

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our consolidated statements of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $128 million during the year ended December 31, 2012.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction (“AFUDC”) is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

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Components and useful lives of property, plant and equipment were as follows:

	December 31,	
	2013	2012
Land and improvements	$878	$551
Buildings and improvements (5 to 45 years)	900	673
Pipelines and equipment (5 to 83 years)	16,966	17,031
Natural gas and NGL storage facilities (5 to 46 years)	1,083	1,057
Bulk storage, equipment and facilities (2 to 83 years)	1,933	1,745
Tanks and other equipment (5 to 40 years)	1,685	1,187
Retail equipment (3 to 99 years)	450	258
Vehicles (1 to 25 years)	124	135
Right of way (20 to 83 years)	1,901	2,042
Furniture and fixtures (2 to 25 years)	48	65
Linepack	116	116
Pad gas	52	58
Other (1 to 48 years)	626	806
Construction work-in-process	1,668	1,688
	28,430	27,412
Less – Accumulated depreciation	(2,483)	(1,639)
Property, plant and equipment, net	$25,947	$25,773

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

	Years Ended December 31,		
	2013	2012	2011
Depreciation expense(1)	$944	$615	$380
Capitalized interest, excluding AFUDC	$43	$99	$11

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

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of August 31 for subsidiaries in our intrastate transportation and storage and midstream segments and during the fourth quarter for subsidiaries in our interstate transportation and storage, NGL transportation and services, and retail marketing segments and all others. We recorded goodwill impairments for the periods presented in these consolidated financial statements.

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Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	NGL Transportation and Services	Investment in Sunoco Logistics	Retail Marketing	All Other	Total
Balance, December 31, 2011	$ 10	$99	$37	$ 432	$—	$—	$642	$1,220
Goodwill acquired	—	1,785	338	—	1,368	1,272	375	5,138
Goodwill sold in deconsolidation of Propane Business	—	—	—	—	—	—	(619)	(619)
Goodwill allocated to the disposal group	—	—	—	—	—	—	(133)	(133)
Balance, December 31, 2012	10	1,884	375	432	1,368	1,272	265	5,606
Goodwill acquired	—	—	—	—	—	156	—	156
Goodwill disposed	—	—	(337)	—	—	—	—	(337)
Goodwill impairment	—	(689)	—	—	—	—	—	(689)
Other	—	—	(2)	—	(22)	17	—	(7)
Balance, December 31, 2013	$ 10	$1,195	$36	$ 432	$1,346	$1,445	$265	$4,729

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. We recorded a net decrease in goodwill of $877 million during the year ended December 31, 2013 primarily due to Trunkline LNG's goodwill impairment of $689 million (see below) and a decrease of $337 million as a result of the SUGS Contribution (see Note 3). These decreases were offset by additional goodwill of $156 million from acquisitions in 2013. This additional goodwill is not expected to be deductible for tax purposes.

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

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

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

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Components and useful lives of intangible assets were as follows:

	December 31, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$1,393	$(164)	$1,290	$(80)
Patents (9 years)	48	(6)	48	(1)
Other (10 to 15 years)	4	(1)	4	(1)
Total amortizable intangible assets	$1,445	$(171)	$1,342	$(82)
Non-amortizable intangible assets:				
Trademarks	294	—	301	—
Total intangible assets	$1,739	$(171)	$1,643	$(82)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2013	2012	2011
Reported in depreciation and amortization	$88	$36	$24

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2014	$93
2015	93
2016	93
2017	93
2018	92

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2013	2012
Unamortized financing costs (3 to 30 years)	$70	$54
Regulatory assets	86	87
Deferred charges	144	140
Restricted funds	378	—
Other	88	76
Total other non-current assets, net	$766	$357

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

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Asset Retirement Obligation

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

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

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

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

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

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

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

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Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2013	2012
Interest payable	$294	$256
Customer advances and deposits	126	44
Accrued capital expenditures	166	356
Accrued wages and benefits	155	236
Taxes payable other than income taxes	214	203
Income taxes payable	3	40
Deferred income taxes	119	130
Other	351	297
Total accrued and other current liabilities	$1,428	$1,562

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2013 was $17.69 billion and $17.09 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of our debt obligations was $17.84 billion and $16.22 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

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 period ended December 31, 2013, no transfers were made between any levels within the fair value hierarchy.

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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 December 31, 2013 and 2012 based on inputs used to derive their fair values:

	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)

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

At December 31, 2013, the fair value of the Trunkline LNG reporting unit was classified as Level 3 of the fair value hierarchy due to the significance of unobservable inputs developed using company-specific information. We used the income approach to measure the fair value of the Trunkline LNG reporting unit. Under the income approach, we calculated the fair value based on the present value of the estimated future cash flows. The discount rate used, which was an unobservable input, was based on the weighted-average cost of capital adjusted for the relevant risk associated with business-specific characteristics and the uncertainty related to the business's ability to execute on the projected cash flows.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of

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construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

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

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

Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to 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 costs and expenses in the consolidated statements of operations, with no effect on net income (loss). Excise taxes collected by our retail marketing segment were $2.22 billion and $573 million for the years ended December 31, 2013 and 2012, respectively.

Income Taxes

ETP is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, ETP would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2013, 2012 and 2011, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. Holdco, which owns Sunoco and Southern Union, is a corporate subsidiary. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

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Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

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

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

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

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

Pensions and Other Postretirement Benefit Plans

Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through AOCI in equity or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements. 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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3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2014 Transactions

Panhandle Merger

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

Trunkline LNG Transaction

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014. 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 expected 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 7.

2013 Transactions

Sale of Southern Union’s Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri agreed to acquire the assets of Southern Union’s MGE division and Laclede Massachusetts agreed to acquire the assets of Southern Union’s NEG division (together, the “LDC Disposal Group”). Laclede Gas Company, a subsidiary of The Laclede Group, Inc., subsequently assumed all of Laclede Missouri’s rights and obligations under the purchase and sale agreement. In February 2013, The Laclede Group, Inc. entered into an agreement with Algonquin Power & Utilities Corp (“APUC”) that allowed a subsidiary of APUC to assume the rights of The Laclede Group, Inc. to purchase the assets of Southern Union’s NEG division.

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

The LDC Disposal Group’s operations have been classified as discontinued operations for all periods in the consolidated statements of operations. The assets and liabilities of the LDC Disposal Group were classified as assets and liabilities held for sale at December 31, 2012.

The following table summarizes selected financial information related to Southern Union’s distribution operations in 2013 through MGE and NEG’s sale dates in September 2013 and December 2013, respectively, and for the period from March 26, 2012 to December 31, 2012:

	Years Ended December 31,	
	2013	2012
Revenue from discontinued operations	$415	$324
Net income of discontinued operations, excluding effect of taxes and overhead allocations	65	43

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SUGS Contribution

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

Acquisition of ETE's Holdco Interest

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

2012 Transactions

Southern Union Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union was the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE. See below for discussion of Holdco Transaction and ETE's contribution of Southern Union to Holdco.

Under the terms of the merger agreement, Southern Union stockholders received a total of 57 million ETE Common Units and a total of approximately $3.01 billion in cash. Effective with the closing of the transaction, Southern Union's common stock was no longer publicly traded.

Citrus Acquisition

In connection with the Southern Union Merger on March 26, 2012, we completed our acquisition of CrossCountry, a subsidiary of Southern Union which owned an indirect 50% interest in Citrus, the owner of FGT. The total merger consideration was approximately $2.0 billion, consisting of approximately $1.9 billion in cash and approximately 2.2 million ETP Common Units. See Note 4 for more information regarding our equity method investment in Citrus.

Sunoco Merger

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

Sunoco generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco also owned a 2% general partner interest, 100% of the IDRs, and 32% of the outstanding common units of Sunoco Logistics. As discussed below, on October 5, 2012, Sunoco's interests in Sunoco Logistics were transferred to the Partnership.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco completed the exit from its Northeast refining operations by contributing the refining assets at its Philadelphia refinery and various commercial contracts to PES, a joint venture with The Carlyle Group. Sunoco also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook facility continued to support operations at the Philadelphia refinery prior to commencement of the PES joint venture. Under the terms of the joint venture agreement, The Carlyle Group contributed cash in exchange for a 67% controlling interest in PES. In exchange for contributing its Philadelphia refinery assets and various commercial contracts to

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the joint venture, Sunoco retained an approximate 33% non-operating noncontrolling interest. The fair value of Sunoco's retained interest in PES, which was $75 million on the date on which the joint venture was formed, was determined based on the equity contributions of The Carlyle Group. Sunoco has indemnified PES for environmental liabilities related to the Philadelphia refinery that arose from the operation of such assets prior the formation of the joint venture. The Carlyle Group will oversee day-to-day operations of PES and the refinery. JPMorgan Chase will provide working capital financing to PES in the form of an asset-backed loan, supply crude oil and other feedstocks to the refinery at the time of processing and purchase certain blendstocks and all finished refined products as they are processed. Sunoco entered into a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

ETP incurred merger related costs related to the Sunoco Merger of $28 million during the year ended December 31, 2012. Sunoco's revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco's net loss included in our consolidated statement of operations was approximately $14 million during October through December 2012. Sunoco Logistics' revenue included in our consolidated statement of operations was approximately $3.11 billion during October through December 2012. Sunoco Logistics' net income included in our consolidated statement of operations was approximately $145 million during October through December 2012.

Holdco Transaction

Immediately following the closing of the Sunoco Merger in 2012, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and retained a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90.7 million Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units were exchanged for Class G Units in 2013 as discussed in Note 7. Pursuant to a stockholders agreement between ETE and ETP, ETP controlled Holdco (prior to ETP's acquisition of ETE's 60% equity interest in Holdco in 2013) and therefore, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

Under the terms of the Holdco transaction agreement, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.

In accordance with GAAP, we have accounted for the Holdco Transaction, whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union). This change only impacted interim periods in 2012, and no prior annual amounts have been adjusted.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Sunoco Merger using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Upon consummation of the Holdco Transaction, we applied the accounting guidance for transactions between entities under common control. In doing so, we recorded the values of assets and liabilities that had been recorded by ETE as reflected below.

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

	Sunoco[(1)]	Southern Union[(2)]
Current assets	$7,312	$556
Property, plant and equipment	6,686	6,242
Goodwill	2,641	2,497
Intangible assets	1,361	55
Investments in unconsolidated affiliates	240	2,023
Note receivable	821	—
Other assets	128	163
	19,189	11,536
Current liabilities	4,424	1,348
Long-term debt obligations, less current maturities	2,879	3,120
Deferred income taxes	1,762	1,419
Other non-current liabilities	769	284
Noncontrolling interest	3,580	—
	13,414	6,171
Total consideration	5,775	5,365
Cash received	2,714	37
Total consideration, net of cash received	$3,061	$5,328

(1) Includes amounts recorded with respect to Sunoco Logistics.
(2) Includes ETP's acquisition of Citrus.

As a result of the Holdco Transaction, we recognized $38 million of merger-related costs during the year ended December 31, 2012 related to Southern Union. Southern Union's revenue included in our consolidated statement of operations was approximately $1.26 billion since the acquisition date to December 31, 2012. Southern Union's net income included in our consolidated statement of operations was approximately $39 million since the acquisition date to December 31, 2012.

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") to AmeriGas. We received approximately $1.46 billion in cash and approximately 30 million AmeriGas common units. AmeriGas assumed approximately $71 million of existing HOLP debt. In connection with the closing of this transaction, we entered into a support agreement with AmeriGas pursuant to which we are obligated to provide contingent, residual support of $1.50 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.50 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

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

In June 2012, we sold the remainder of our retail propane operations, consisting of our cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and we received net proceeds of approximately $43 million.

Sale of Canyon

In October 2012, we sold Canyon for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been restated to present Canyon's operations as discontinued operations. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $132 million during the year ended December 31, 2012. Canyon was previously included in our midstream segment.

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2011 Transaction

LDH Acquisition

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

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

We accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star’s results of operations are included in our NGL transportation and services segment. Regency’s 30% interest in Lone Star is reflected as noncontrolling interest.

Pro Forma Results of Operations

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

	Years Ended December 31,	
	2012	2011
Revenues	$39,136	$36,169
Net income	1,133	1,027
Net income attributable to partners	788	745
Basic net income per Limited Partner unit	$1.33	$1.24
Diluted net income per Limited Partner unit	$1.33	$1.24

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star, Southern Union and Sunoco beginning January 1, 2011;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting;
- include incremental interest expense related to the financing of ETP’s proportionate share of the purchase price; and
- reflect noncontrolling interest related to ETE’s 60% interest in Holdco during the periods.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Regency

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 (see Note 3). The consideration paid by Regency in connection with this transaction included approximately 31.4 million Regency common units, approximately 6.3 million Regency Class F units, the distribution of $463 million in cash to Southern Union, net of closing adjustments, and the payment of $30 million in cash to a subsidiary of ETP. This direct investment in Regency common and Class F units received has been accounted for using the equity method.

The carrying amount of our investment in Regency was $1.41 billion as of December 31, 2013 and was reflected in our all other segment.

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Citrus Corp.

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry, a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus, merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105 million of ETP Common Units (the "Citrus Acquisition") to a subsidiary of ETE. As a result of the consummation of the Citrus Acquisition, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

We recorded our investment in Citrus at $2.0 billion, which exceeded our proportionate share of Citrus' equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting. The carrying amount of our investment in Citrus was $1.89 billion and $1.98 billion as of December 31, 2013 and 2012, respectively, and was reflected in our interstate transportation and storage segment.

AmeriGas Partners, L.P.

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

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

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

FEP

We have a 50% interest in FEP, a 50/50 joint venture with KMP. FEP owns the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The carrying amount of our investment in FEP was $144 million and $159 million as of December 31, 2013 and 2012, respectively, and was reflected in our interstate transportation and storage segment.

Summarized Financial Information

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

	December 31,	
	2013	2012
Current assets	$1,372	$878
Property, plant and equipment, net	12,320	8,063
Other assets	6,478	2,529
Total assets	$20,170	$11,470
Current liabilities	$1,455	$1,605
Non-current liabilities	10,286	6,143
Equity	8,429	3,722
Total liabilities and equity	$20,170	$11,470

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	Years Ended December 31,		
	2013	2012	2011
Revenue	$6,806	$4,057	$3,337
Operating income	1,043	635	681
Net income	574	338	341

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

5. NET INCOME PER LIMITED PARTNER UNIT:

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

	Years Ended December 31,		
	2013	2012	2011
Income from continuing operations	$735	$1,757	$700
Less: Income from continuing operations attributable to noncontrolling interest	296	62	28
Income from continuing operations, net of noncontrolling interest	439	1,695	672
General Partner's interest in income from continuing operations	505	463	433
Limited Partners' interest in income (loss) from continuing operations	(66)	1,232	239
Additional earnings allocated (to) from General Partner	(2)	1	1
Distributions on employee unit awards, net of allocation to General Partner	(10)	(9)	(8)
Income (loss) from continuing operations available to Limited Partners	$(78)	$1,224	$232
Weighted average Limited Partner units – basic	343.4	248.3	207.2
Basic income (loss) from continuing operations per Limited Partner unit	$(0.23)	$4.93	$1.12
Dilutive effect of unvested Unit Awards	—	0.7	0.9
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	343.4	249.0	208.1
Diluted income (loss) from continuing operations per Limited Partner unit	$(0.23)	$4.91	$1.12
Basic income (loss) from discontinued operations per Limited Partner unit	$0.05	$(0.50)	$(0.02)
Diluted income (loss) from discontinued operations per Limited Partner unit	$0.05	$(0.50)	$(0.02)

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2013	2012
ETP Debt		
6.0% Senior Notes due July 1, 2013	$—	$350
8.5% Senior Notes due April 15, 2014	292	292
5.95% Senior Notes due February 1, 2015	750	750
6.125% Senior Notes due February 15, 2017	400	400

6.7% Senior Notes due July 1, 2018	600	600
9.7% Senior Notes due March 15, 2019	400	400
9.0% Senior Notes due April 15, 2019	450	450
4.15% Senior Notes due October 1, 2020	700	—
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
3.60% Senior Notes due February 1, 2023	800	—
4.9% Senior Notes due February 1, 2024	350	—
7.6% Senior Notes due February 1, 2024	277	—
8.25% Senior Notes due November 15, 2029	267	—
6.625% Senior Notes due October 15, 2036	400	400
7.5% Senior Notes due July 1, 2038	550	550
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	—
5.95% Senior Notes due October 1, 2043	450	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	—
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Unamortized premiums, discounts and fair value adjustments, net	(34)	(14)
	11,213	9,073
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	88	88
5.54% Senior Notes due November 17, 2016	125	125
5.64% Senior Notes due May 24, 2017	82	82
5.36% Senior Notes due December 9, 2020	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Unamortized premiums, discounts and fair value adjustments, net	(1)	(1)
	869	869
Southern Union Debt(1)		
7.60% Senior Notes due February 1, 2024	82	360
8.25% Senior Notes due November 14, 2029	33	300
Floating Rate Junior Subordinated Notes due November 1, 2066	54	600
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Unamortized premiums, discounts and fair value adjustments, net	48	49
	217	1,519
Panhandle Debt		
6.05% Senior Notes due August 15, 2013	—	250
6.20% Senior Notes due November 1, 2017	300	300
7.00% Senior Notes due June 15, 2018	400	400
8.125% Senior Notes due June 1, 2019	150	150
7.00% Senior Notes due July 15, 2029	66	66
Term Loan due February 23, 2015	—	455
Unamortized premiums, discounts and fair value adjustments, net	107	136
	1,023	1,757

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Sunoco Debt		
4.875% Senior Notes due October 15, 2014	250	250
9.625% Senior Notes due April 15, 2015	250	250
5.75% Senior Notes due January 15, 2017	400	400
9.00% Debentures due November 1, 2024	65	65
Unamortized premiums, discounts and fair value adjustments, net	70	104
	1,035	1,069
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014[(2)]	175	175
6.125% Senior Notes due May 15, 2016	175	175
5.50% Senior Notes due February 15, 2020	250	250
4.65% Senior Notes due February 15, 2022	300	300
3.45% Senior Notes due January 15, 2023	350	—
6.85% Senior Notes due February 15, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Unamortized premiums, discounts and fair value adjustments, net	118	143
	2,503	1,732
Note Payable to ETE	—	166
Other	228	32
	17,088	16,217
Less: current maturities	637	609
	$16,451	$15,608

(1) In connection with the Panhandle Merger, Southern Union’s debt obligations were assumed by Panhandle.

(2) Sunoco Logistics’ 8.75% Senior Notes due February 15, 2014 were classified as long-term debt as Sunoco Logistics repaid these notes in February 2014 with borrowings under its $1.50 billion credit facility due November 2018.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $308 million in unamortized net premiums and fair value adjustments:

2014	$812
2015	1,047
2016	375
2017	1,220
2018	1,205
Thereafter	12,121
Total	$16,780

ETP as Co-Obligor of Sunoco Debt

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

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ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern Senior Notes

The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

Note Payable – ETE

On March 26, 2012, Southern Union received $221 million from ETE to pay certain expenses in connection with the Merger, including (i) payments made to employees related to outstanding awards of stock options, stock appreciation rights and RSUs; and (ii) payments to certain executives under applicable employment or change in control agreements, which provided for compensation when their employment was terminated in connection with a change in control. In connection with the receipt of the $221 million from ETE, on March 26, 2012, Southern Union entered into an interest-bearing promissory note payable due on or before March 25, 2013. The interest rate under the promissory note was 3.25% and accrued interest was payable monthly in arrears. A payment of $55 million to ETE was made in May 2012, and the outstanding balance of $166 million was assumed by Holdco as of December 31, 2012 and the maturity date of the note payable was extended to January 22, 2014. The note payable outstanding was paid in 2013.

Southern Union Junior Subordinated Notes

The interest rate on the remaining portion of Southern Union's $600 million Junior Subordinated Notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the Junior Subordinated Notes was $600 million at an effective interest rate of 3.32% at December 31, 2013.

Panhandle Term Loans

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

January 2013 Senior Notes Offerings

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

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

September 2013 Senior Notes Offering

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

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Note Exchange

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

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt. We use the ETP Credit Facility to provide temporary financing for our growth projects, as well as for general partnership purposes.

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

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

Southern Union Credit Facility

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

Sunoco Logistics Credit Facilities

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

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

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

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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

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The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The credit agreement relating to the ETP Credit Facility also contains a financial covenant that provides that the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1 as of the end of each quarter, with a permitted increase to 5.5 to 1 during a Specified Acquisition Period, as defined in the ETP Credit Facility.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

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

Covenants Related to Southern Union

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

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

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

Covenants Related to Sunoco Logistics

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

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fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

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

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

7. EQUITY:

Limited Partner interests are represented by Common, Class E Units, Class G Units and Class H Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. As of December 31, 2013, there were issued and outstanding 333.8 million Common Units representing an aggregate 99.3% Limited Partner interest in us. There are also 8.9 million Class E Units and 90.7 million Class G Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms. There are also 50.2 million Class H Units outstanding representing Limited Partner interests owned by ETE Holdings (see "Class H Units" below).

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash (as defined in our Partnership Agreement) from operating surplus after the minimum quarterly distribution has been paid. Please read "Quarterly Distributions of Available Cash" below. ETP GP, a wholly-owned subsidiary of ETE, owns all of the IDRs.

Common Units

The change in Common Units was as follows:

	Years Ended December 31,		
	2013	2012	2011
Number of Common Units, beginning of period	301.5	225.5	193.2
Common Units issued in connection with public offerings	13.8	15.5	29.4
Common Units issued in connection with certain acquisitions	49.5	57.4	0.1
Common Units redeemed for Class H Units	(50.2)	—	—
Common Units issued in connection with the Distribution Reinvestment Plan	2.3	1.0	0.4
Common Units issued in connection with Equity Distribution Agreements	16.9	1.6	2.0
Repurchases of Common Units in open-market transactions	(0.4)	—	—
Issuance of Common Units under equity incentive plans	0.4	0.5	0.4
Number of Common Units, end of period	333.8	301.5	225.5

Our Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

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Public Offerings

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

Date	Number of Common Units	Price per Unit	Net Proceeds
April 2011	14.2	$50.52	$695
November 2011	15.2	44.67	660
July 2012	15.5	44.57	671
April 2013	13.8	48.05	657

Proceeds from the offerings listed above were used to repay amounts outstanding under the ETP Credit Facility and/or to fund capital expenditures and capital contributions to joint ventures, and for general partnership purposes.

Equity Distribution Program

From time to time, we have sold Common Units through an equity distribution agreement. Such sales of Common Units are made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent which is the counterparty to the equity distribution agreement.

In January 2013 and May 2013, we entered into equity distribution agreements pursuant to which we may sell from time to time Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the year ended December 31, 2013, we issued approximately 16.9 million units for $846 million, net of commissions of $9 million. Approximately $145 million of our Common Units remained available to be issued under the currently effective equity distribution agreements as of December 31, 2013.

Equity Incentive Plan Activity

As discussed in Note 8, we issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Distribution Reinvestment Program

In April 2011, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the "DRIP"). The DRIP provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. The registration statement covers the issuance of up to 5.8 million Common Units under the DRIP.

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

Class E Units

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

Class G Units

In conjunction with the Sunoco Merger, we amended our partnership agreement to create the Class F Units. The number of Class F Units issued was determined at the closing of the Sunoco Merger and equaled 90.7 million, which included 40 million Class F Units issued in exchange for cash contributed by Sunoco to us immediately prior to or concurrent with the closing of the Sunoco Merger. The Class F Units generally did not have any voting rights. The Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by us and our subsidiaries, other than Holdco, and

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available for distribution, up to a maximum of $3.75 per Class F Unit per year. In April 2013, all of the outstanding Class F Units were exchanged for Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are held by a subsidiary and therefore are reflected as treasury units in the consolidated financial statements.

Class H Units

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

Quarterly Distributions of Available Cash

The Partnership Agreement requires that we distribute all of our Available Cash to our Unitholders and our General Partner within forty-five days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any of our fiscal quarters, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of our business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in our Partnership Agreement.

Our distributions of Available Cash from operating surplus, excluding incentive distributions, to our General Partner and Limited Partner interests are based on their respective interests as of the distribution record date. Incentive distributions allocated to our General Partner are determined based on the amount by which quarterly distribution to common Unitholders exceed certain specified target levels, as set forth in our Partnership Agreement.

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Distributions declared during the periods presented below are summarized as follows:

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

Following are incentive distributions ETE has agreed to relinquish:

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

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

In addition to the amounts above, in connection with the Partnership's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of incentive distributions of $50 million, $50 million, $45 million and $35 million for the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

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

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

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Sunoco Logistics Quarterly Distributions of Available Cash

Distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$0.54500
March 31, 2013	May 9, 2013	May 15, 2013	0.57250
June 30, 2013	August 8, 2013	August 14, 2013	0.60000
September 30, 2013	November 8, 2013	November 14, 2013	0.63000
December 31, 2013	February 10, 2014	February 14, 2014	0.66250

Accumulated Other Comprehensive Income (Loss)

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

	December 31, 2013	2012
Available-for-sale securities	$2	$—
Foreign currency translation adjustment	(1)	—
Net loss on commodity related hedges	(4)	—
Actuarial gain (loss) related to pensions and other postretirement benefits	56	(10)
Equity investments, net	8	(9)
Subtotal	61	(19)
Amounts attributable to noncontrolling interest	—	6
Total AOCI, net of tax	$61	$(13)

The tables below set forth the tax amounts included in the respective components of other comprehensive income (loss) for the periods presented:

	December 31, 2013	2012
Net gains on commodity related hedges	$—	$1
Actuarial (gain) loss relating to pension and other postretirement benefits	(39)	5
Total	$(39)	$6

8. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2013, an aggregate total of 0.9 million ETP Common Units remain available to be awarded under our equity incentive plans.

Unit Grants

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as "distribution equivalent rights." Under our equity incentive plans, our non-employee directors each receive grants with a five-year service vesting requirement.

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Award Activity

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

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

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

Sunoco Logistics' Unit-Based Compensation Plan

Sunoco Logistics' general partner has a long-term incentive plan for employees and directors, which permits the grant of restricted units and unit options of Sunoco Logistics covering an additional 0.6 million Sunoco common units. As of December 31, 2013, a total of 0.6 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $21 million of expense over a weighted-average period of 2.8 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of the entity that indirectly owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a 5 year vesting schedule whereby the officer vested in the ETE units at a rate of 20% per year. As these ETE units conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards were paid by ETP or ETE. As these units were outstanding prior to these awards, these awards did not represent an increase in the number of outstanding units of either ETP or ETE and were not dilutive to cash distributions per unit with respect to either ETP or ETE.

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

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9. INCOME TAXES:

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

	Years Ended December 31,		
	2013	2012	2011
Current expense (benefit):			
Federal	$51	$(3)	$(1)
State	(2)	4	16
Total	49	1	15
Deferred expense:			
Federal	(6)	45	4
State	54	17	—
Total	48	62	4
Total income tax expense from continuing operations	$97	$63	$19

Historically, our effective rate differed from the statutory rate primarily due to Partnership earnings that are not subject to U.S. federal and most state income taxes at the Partnership level. The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the activities conducted through corporate subsidiaries. A reconciliation of income tax expense (benefit) at the U.S. statutory rate to the income tax expense (benefit) attributable to continuing operations for the years ended December 31, 2013 and 2012 is as follows:

	December 31, 2013			December 31, 2012		
	Corporate Subsidiaries(1)	Partnership(2)	Consolidated	Corporate Subsidiaries(1)	Partnership(2)	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$(166)	$—	$(166)	$1	$—	$1
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	241	—	241	—	—	—
Nondeductible executive compensation	—	—	—	28	—	28
State income taxes (net of federal income tax effects)	31	5	36	9	7	16
Other	(13)	(1)	(14)	18	—	18
Income tax from continuing operations	$93	$4	$97	$56	$7	$63

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

(2) Includes ETP and its subsidiaries that are classified as pass-through entities for federal income tax purposes.

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Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31, 2013	2012
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$217	$268
Pension and other postretirement benefits	57	127
Long term debt	108	117
Other	104	288
Total deferred income tax assets	486	800
Valuation allowance	(74)	(90)
Net deferred income tax assets	$412	$710
Deferred income tax liabilities:		
Properties, plants and equipment	$(1,522)	$(1,938)
Inventory	(302)	(516)
Investment in unconsolidated affiliates	(2,244)	(1,542)
Trademarks	(180)	(192)
Other	(45)	(128)
Total deferred income tax liabilities	(4,293)	(4,316)
Net deferred income tax liability	(3,881)	(3,606)
Less: current portion of deferred income tax assets (liabilities)	(119)	(130)
Accumulated deferred income taxes	$(3,762)	$(3,476)

The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the deferred tax assets (liabilities). The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31, 2013	2012
Net deferred income tax liability, beginning of year	$(3,606)	$(123)
Southern Union acquisition	—	(1,420)
Sunoco acquisition	—	(1,989)
SUGS Contribution to Regency	(115)	—
Tax provision (including discontinued operations)	(111)	(73)
Other	(49)	(1)
Net deferred income tax liability	$(3,881)	$(3,606)

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

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

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

As of December 31, 2013, we have $425 million ($418 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate. We believe it is reasonably possible that its unrecognized tax benefits may be reduced by $6 million ($5 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco's 2004 through 2011 open statute years, Sunoco has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco is fully successful with its claims, it will receive tax refunds of approximately $372 million. However, due to the uncertainty surrounding the claims, a reserve of $372 million was established for the full amount of the claims. Due to the timing of the expected settlement of the claims and the related reserve, the receivable and the reserve for this issue have been netted in the financial statements as of December 31, 2013.

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

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

Sunoco has been examined by the IRS for the 2007 and 2008 tax years; however, the statutes remain open for both of these tax years due to carryback of net operating losses. Sunoco is currently under examination for the years 2009 through 2011, but due to the aforementioned carryback, such years also impact Sunoco's tax liability for the years 2004 through 2008. With the exception of the claims regarding government incentive payments discussed above, all issues are resolved. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2013, the IRS has proposed only one adjustment for the years under examination. For the 2006 tax year, the IRS is challenging $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of its distribution operations and its gathering and processing operations. We will vigorously defend and believe Southern Union's tax position will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to this tax position.

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

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

FERC Audit

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

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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.

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 ICA and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Commitments

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

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $140 million, $57 million and $26 million for the years ended December 31, 2013, 2012 and 2011, respectively, which include contingent rentals totaling $22 million and $6 million in 2013 and 2012, respectively. During the years ended December 31, 2013 and 2012, approximately $24 million and $4 million, respectively, of rental expense was recovered through related sublease rental income.

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Future minimum lease commitments for such leases are:

Years Ending December 31:	
2014	$80
2015	78
2016	70
2017	66
2018	53
Thereafter	420
Future minimum lease commitments	767
Less: Sublease rental income	(57)
Net future minimum lease commitments	$710

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

Litigation and Contingencies

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

Sunoco Litigation

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

Litigation Relating to the Southern Union Merger

In June 2011, several putative class action lawsuits were filed in the Judicial District Court of Harris County, Texas naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. The lawsuits were styled Jaroslawicz v. Southern Union Company, et al., Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas and Magda v. Southern Union Company, et al., Cause No. 2011-37134, in the 11th Judicial District Court of Harris County, Texas. The lawsuits were consolidated into an action styled In re: Southern Union Company; Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas. Plaintiffs allege that the Southern Union directors breached their fiduciary duties to Southern Union's stockholders in connection with the Merger and that Southern Union and ETE aided and abetted the alleged breaches of fiduciary duty. The amended petitions allege that the Merger involves an unfair price and an inadequate sales process, that Southern Union’s directors entered into the Merger to benefit themselves personally, including

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through consulting and noncompete agreements, and that defendants have failed to disclose all material information related to the Merger to Southern Union stockholders. The amended petitions seek injunctive relief, including an injunction of the Merger, and an award of attorneys' and other fees and costs, in addition to other relief. On October 21, 2011, the court denied ETE's October 13, 2011, motion to stay the Texas proceeding in favor of cases pending in the Delaware Court of Chancery.

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

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

MTBE Litigation

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

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

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

Other Litigation and Contingencies

In November 2011, a derivative lawsuit was filed in the Judicial District Court of Harris County, Texas naming as defendants ETP, ETP GP, ETP LLC, the boards of directors of ETP LLC (collectively with ETP GP and ETP LLC, the "ETP Defendants"), certain members of management for ETP and ETE, ETE, and Southern Union. The lawsuit is styled W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, in the 157th Judicial District Court of Harris County, Texas. Plaintiffs assert claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and the individual defendants. Plaintiffs also assert claims for aiding and abetting and tortious interference with contract against Southern Union. On October 5, 2012, certain defendants filed a motion for summary judgment with respect to the primary allegations in this action. On December 13, 2012, Plaintiffs filed their opposition to the motion for summary judgment. Defendants filed a reply on December 19, 2012. On

December 20, 2012, the court conducted an oral hearing on the motion. Plaintiffs filed a post-hearing sur-reply on January 7, 2013. On January 16, 2013, the Court granted defendants' motion for summary judgment. The parties agreed to settle the matter and executed a memorandum of understanding. On October 4, 2013, the Court approved the settlement and ordered the case dismissed with prejudice.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable

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outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2013 and 2012, accruals of approximately $46 million and $42 million, respectively, were reflected on our 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.

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

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

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General (“AG”) filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged “excessive and imprudently incurred costs” related to legal fees associated with Southern Union’s environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company’s collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling 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 applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Southern Union believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Southern Union will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Environmental Matters

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

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future.

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Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

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

Environmental Remediation

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

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Southern Union's distribution operations are responsible for soil and groundwater remediation at certain sites related to manufactured gas plants ("MGPs") and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party ("PRP"). As of December 31, 2013, Sunoco had been named as a PRP at 40 identified or potentially identifiable as "Superfund" sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco's purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

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

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

	December 31,	
	2013	2012
Current	$45	$46
Non-current	350	165
Total environmental liabilities	$395	$211

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

During the years ended December 31, 2013 and 2012, Sunoco had $36 million and $12 million, respectively, of expenditures related to environmental cleanup programs.

The EPA's Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules.

Costs associated with tank

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integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

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

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

Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline 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.

11. 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

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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 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.

Derivatives are utilized in our all other segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist.

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The following table details our outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	9,457,500	2014-2019	—	—
Basis Swaps IFERC/NYMEX(1)	(487,500)	2014-2017	(30,980,000)	2013-2014
Swing Swaps	1,937,500	2014-2016	—	—
Power (Megawatt):				
Forwards	351,050	2014	19,650	2013
Futures	(772,476)	2014	(1,509,300)	2013
Options – Puts	(52,800)	2014	—	—
Options – Calls	103,200	2014	1,656,400	2013
Crude (Bbls) – Futures	103,000	2014	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	570,000	2014	150,000	2013
Swing Swaps IFERC	(9,690,000)	2014-2016	(83,292,500)	2013
Fixed Swaps/Futures	(8,195,000)	2014-2015	27,077,500	2013
Forward Physical Contracts	5,668,559	2014-2015	11,689,855	2013-2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	2014	(30,000)	2013
Refined Products (Bbls) – Futures	(1,133,600)	2014	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(7,352,500)	2014	(18,655,000)	2013
Fixed Swaps/Futures	(50,530,000)	2014	(44,272,500)	2013
Hedged Item – Inventory	50,530,000	2014	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,825,000)	2014	—	—
Fixed Swaps/Futures	(12,775,000)	2014	(8,212,500)	2013
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	2014	(930,000)	2013
Refined Products (Bbls) – Futures	—	—	(98,000)	2013
Crude (Bbls) – Futures	(30,000)	2014	—	—

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

We expect gains of $4 million related to 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 December 31, 2013	December 31, 2012
ETP	July 2013[(2)]	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$—	$400
ETP	July 2014[(2)]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union[(3)]	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union[(3)]	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

(1) Floating rates are based on 3-month LIBOR.
(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date. During the year ended December 31, 2013, we settled $400 million of ETP's forward-starting interest rate swaps that had an effective date of July 2013.
(3) In connection with the Panhandle Merger, Southern Union's interest rate swaps outstanding were assumed by Panhandle.

Credit Risk

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

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Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$3	$8	$(18)	$(10)
	3	8	(18)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	227	110	(209)	(116)
Commodity derivatives	39	33	(38)	(34)
Current assets held for sale	—	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	—	(9)
Interest rate derivatives	47	55	(95)	(223)
	313	200	(342)	(382)
Total derivatives	$316	$208	$(360)	$(392)

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

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

	Balance Sheet Location	Asset Derivatives		Liability Derivatives	
		December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$41	$28	$(38)	$(27)
Broker cleared derivative contracts	Other current assets (liabilities)	265	150	(318)	(228)
		306	178	(356)	(255)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	2
Counterparty netting	Price risk management assets (liabilities)	(36)	(25)	36	25
Payments on margin deposit	Other current assets	(1)	—	55	59
		(37)	(25)	91	86
Net derivatives with offsetting agreements		269	153	(265)	(169)
Derivatives without offsetting agreements		47	55	(95)	(223)
Total derivatives		$316	$208	$(360)	$(392)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion)		
	Years Ended December 31,		
	2013	2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$(1)	$8	$19
Total	$(1)	$8	$19

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$4	$14	$38
Total		$4	$14	$38

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$8	$54	$34
Total		$8	$54	$34

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$(11)	$(7)	$(30)
Commodity derivatives – Non-trading	Cost of products sold	(12)	(15)	9
Commodity contracts – Non-trading	Deferred gas purchases	(3)	(26)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	44	(4)	(77)
Total		$18	$(52)	$(98)

12. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. We and our

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subsidiaries made matching contributions of $38 million, $21 million and $11 million to these 401(k) savings plans for the years ended December 31, 2013, 2012 and 2011, respectively.

Pension and Other Postretirement Benefit Plans

Southern Union

Southern Union has funded non-contributory defined benefit pension plans that cover substantially all employees of Southern Union's distribution operations. Normal retirement age is 65, but certain plan provisions allow for earlier retirement. Pension benefits are calculated under formulas principally based on average earnings and length of service for salaried and non-union employees and average earnings and length of service or negotiated non-wage based formulas for union employees.

The 2012 postretirement benefits expense for Southern Union reflects the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. Southern Union previously had postretirement health care and life insurance plans that covered substantially of its distribution and transportation and storage operations employees as well as all corporate employees. The health care plans generally provide for cost sharing between Southern Union and its retirees in the form of retiree contributions, deductibles, coinsurance, and a fixed cost cap on the amount Southern Union pays annually to provide future retiree health care coverage under certain of these plans.

Sunoco

Sunoco has both funded and unfunded noncontributory defined benefit pension plans. Sunoco also has plans which provide health care benefits for substantially all of its current retirees ("postretirement benefit plans"). The postretirement benefit plans are unfunded and the costs are shared by Sunoco and its retirees. Prior to the Sunoco Merger on October 5, 2012, pension benefits under Sunoco's defined benefit plans were frozen for most of the participants in these plans at which time Sunoco instituted a discretionary profit-sharing contribution on behalf of these employees in its defined contribution plan. Postretirement medical benefits were also phased down or eliminated for all employees retiring after July 1, 2010. Sunoco has established a trust for its postretirement benefit liabilities by making a tax-deductible contribution of approximately $200 million and restructuring the retiree medical plan to eliminate Sunoco's liability beyond this funded amount. The retiree medical plan change eliminated substantially all of Sunoco's future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

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Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Change in benefit obligation:					
Benefit obligation at beginning of period	$1,117	$78	$296	$1,257	$359
Service cost	3	—	—	3	1
Interest cost	33	2	6	15	3
Amendments	—	—	2	—	17
Benefits paid, net	(99)	(16)	(26)	(71)	(8)
Curtailments	—	—	—	—	(80)
Actuarial (gain) loss and other	(74)	(3)	(14)	(9)	4
Settlements	(95)	—	—	—	—
Dispositions	(253)	—	(41)	—	—
Benefit obligation at end of period	632	61	223	1,195	296
Change in plan assets:					
Fair value of plan assets at beginning of period	906	—	312	941	306
Return on plan assets and other	43	—	17	22	5
Employer contributions	—	—	8	14	9
Benefits paid, net	(99)	—	(26)	(71)	(8)
Settlements	(95)	—	—	—	—
Dispositions	(155)	—	(27)	—	—
Fair value of plan assets at end of period	600	—	284	906	312
Amount underfunded (overfunded) at end of period	$32	$61	$(61)	$289	$(16)
Amounts recognized in the consolidated balance sheets consist of:					
Non-current assets	$—	$—	$86	$—	$59
Current liabilities	—	(9)	(2)	(15)	(2)
Non-current liabilities	(32)	(52)	(23)	(274)	(41)
	$(32)	$(61)	$61	$(289)	$16
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:					
Net actuarial gain	$(86)	$(4)	$(25)	$(1)	$(1)
Prior service cost	—	—	18	—	16

$(86)	$(4)	$(7)	$(1)	$15

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The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Projected benefit obligation	$632	$61	N/A	$1,195	N/A
Accumulated benefit obligation	632	61	223	1,179	$225
Fair value of plan assets	600	—	284	906	185

Components of Net Periodic Benefit Cost

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$3	$—	$3	$1
Interest cost	35	6	15	3
Expected return on plan assets	(54)	(9)	(21)	(5)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	2	—	—	—
Special termination benefits charge	—	—	2	—
Curtailment recognition[1]	—	—	—	(15)
Settlements	(2)	—	—	—
	(16)	(2)	(1)	(16)
Regulatory adjustment[2]	5	—	9	2
Net periodic benefit cost	$(11)	$(2)	$8	$(14)

(1) Subsequent to the Southern Union Merger, Southern Union amended certain of its other postretirement employee benefit plans, which prospectively restrict participation in the plans for the impacted active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, Southern Union recorded a pre-tax curtailment gain of $75 million. Such gain was offset by establishment of a non-current refund liability in the amount of $60 million. As such, the net curtailment gain recognition was $15 million.

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

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65%	2.33%	3.41%	2.39%
Rate of compensation increase	N/A	N/A	3.17%	N/A

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The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.50 %	2.68 %	2.37 %	2.43 %
Expected return on assets:				
Tax exempt accounts	7.50 %	6.95 %	7.63 %	7.00 %
Taxable accounts	N/A	4.42 %	N/A	4.50 %
Rate of compensation increase	N/A	N/A	3.02 %	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by Southern Union and Sunoco's other postretirement benefit plans are shown in the table below:

	December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.57 %	7.78 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.42 %	5.32 %
Year that the rate reaches the ultimate trend rate	2018	2018

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Southern Union plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its pension plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 70%, fixed income of 15% to 35%, alternative assets of 10% to 35% and cash of 0% to 10%. To achieve diversity within its other postretirement plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of 0% to 10%.

The investment strategy of Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns, maintain a sufficient funded status of the plans and limit required contributions. Sunoco has targeted the following asset allocations: equity of 35%, fixed income of 55%, and private equity investments of 10%. Sunoco anticipates future shifts in targeted asset allocation from equity securities to fixed income securities if funding levels improve due to asset performance or Sunoco contributions.

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The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$12	$12	$—	$—
Mutual funds(1)	368	—	281	87
Fixed income securities	220	—	220	—
Total	$600	$12	$501	$87

(1) Primarily comprised of approximately 66% equities, 10% fixed income securities, and 24% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$25	$25	$—	$—
Mutual funds(1)	516	—	433	83
Fixed income securities	354	—	354	—
Multi-strategy hedge funds(2)	11	—	11	—
Total	$906	$25	$798	$83

(1) Primarily comprised of approximately 36% equities, 54% fixed income securities, and 10% in other investments as of December 31, 2012.

(2) Primarily includes hedge funds that invest in multiple strategies, including relative value, opportunistic/macro, long/short equities, merger arbitrage/event driven, credit, and short selling strategies, to generate long-term capital appreciation through a portfolio having a diversified risk profile with relatively low volatility and a low correlation with traditional equity and fixed-income markets. These investments can generally be redeemed effective as of the last day of a calendar quarter at the net asset value per share of the investment with approximately 65 days prior written notice.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$10	$10	$—	$—
Mutual funds(1)	130	112	18	—
Fixed income securities	144	—	144	—
Total	$284	$122	$162	$—

(1) Primarily comprised of approximately 41% equities, 48% fixed income securities, 6% cash, and 5% in other investments as of December 31, 2013.

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	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$7	$7	$—	$—
Mutual funds(1)	147	126	21	—
Fixed income securities	158	—	158	—
Total	$312	$133	$179	$—

(1) Primarily comprised of approximately 19% equities, 74% fixed income securities, 4% cash, and 3% in other investments as of December 31, 2012.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines. See Note 2 for information related to the framework used to measure the fair value of its pension and other postretirement plan assets.

Contributions

We expect to contribute approximately $23 million to pension plans and approximately $18 million to other postretirement plans in 2014. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Southern Union and Sunoco's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

	Pension Benefits		
Years	Funded Plans	Unfunded Plans	Other Postretirement Benefits (Gross, Before Medicare Part D)
2014	$82	$9	$31
2015	77	9	29
2016	67	8	28
2017	61	7	26
2018	56	7	24
2019 – 2023	220	23	87

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Southern Union does not expect to receive any Medicare Part D subsidies in any future periods.

13. RELATED PARTY TRANSACTIONS:

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

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

Sunoco Logistics has an agreement with PES relating to the Fort Mifflin Terminal Complex. Under this agreement, PES will deliver an average of 300,000 Bbls/d of crude oil and refined products per contract year at the Fort Mifflin facility. PES does not have exclusive use of the Fort Mifflin Terminal Complex; however, Sunoco Logistics is obligated to provide the necessary

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tanks, marine docks and pipelines for PES to meet its minimum requirements under the agreement. Sunoco Logistics entered into a ten-year agreement to provide terminalling services to PES in September 2012.

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

In connection with the acquisition of the Marcus Hook Facility, Sunoco Logistics assumed an agreement to provide butane storage and terminal services to PES at the facility. The 10 year agreement extends through September 2022.

Sunoco Logistics has agreements with PES whereby PES purchases crude oil, at market-based rates, for delivery to Sunoco Logistics' Fort Mifflin and Eagle Point terminal facilities. These agreements contain minimum volume commitments and extend through 2014.

The renegotiated terms of the agreements with PES provide PES with the option to purchase the Fort Mifflin and Belmont terminals if certain triggering events occur, including a sale of substantially all of the assets or operations of the Philadelphia refinery, an initial public offering or a public debt filing of more than $200 million. The purchase price for each facility would be established based on a fair value amount determined by designated third parties.

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

	Years Ended December 31,		
	2013	2012	2011
Affiliated revenues	$1,550	$173	$690

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

	December 31,	
	2013	2012
Accounts receivable from related companies:		
ETE	$18	$16
Regency	53	10
PES	7	60
FGT	29	2
Eastern Gulf	24	—
Other	34	6
Total accounts receivable from related companies:	$165	$94
Accounts payable to related companies:		
ETE	$8	$7
Regency	24	2
PES	—	13
FGT	8	—
Other	5	2
Total accounts payable to related companies:	$45	$24

14. REPORTABLE SEGMENTS:

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

- intrastate transportation and storage;

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•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 the financial information by segment:

	Years Ended December 31,		
	2013	2012	2011
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$2,250	$2,012	$2,398
Intersegment revenues	202	179	276
	2,452	2,191	2,674
Interstate transportation and storage:			
Revenues from external customers	1,270	1,109	447
Intersegment revenues	39	—	—
	1,309	1,109	447
Midstream:			
Revenues from external customers	1,307	1,757	1,082
Intersegment revenues	942	196	401
	2,249	1,953	1,483
NGL transportation and services:			
Revenues from external customers	2,063	619	363
Intersegment revenues	64	31	34
	2,127	650	397
Investment in Sunoco Logistics:			
Revenues from external customers	16,480	3,109	—
Intersegment revenues	159	80	—
	16,639	3,189	—
Retail marketing:			
Revenues from external customers	21,004	5,926	—
Intersegment revenues	8	—	—
	21,012	5,926	—
All other:			
Revenues from external customers	1,965	1,170	2,509
Intersegment revenues	402	385	379
	2,367	1,555	2,888
Eliminations	(1,816)	(871)	(1,090)
Total revenues	$46,339	$15,702	$6,799

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	Years Ended December 31,		
	2013	2012	2011
Cost of products sold:			
Intrastate transportation and storage	$1,737	$1,394	$1,774
Midstream	1,579	1,273	988
NGL transportation and services	1,655	361	218
Investment in Sunoco Logistics	15,574	2,885	—
Retail marketing	20,150	5,757	—
All other	2,309	1,496	2,274
Eliminations	(1,800)	(900)	(1,079)
Total cost of products sold	$41,204	$12,266	$4,175

	Years Ended December 31,		
	2013	2012	2011
Depreciation and amortization:			
Intrastate transportation and storage	$122	$122	$120
Interstate transportation and storage	244	209	81
Midstream	172	168	85
NGL transportation and services	91	53	32
Investment in Sunoco Logistics	265	63	—
Retail marketing	114	28	—
All other	24	13	87
Total depreciation and amortization	$1,032	$656	$405

	Years Ended December 31,		
	2013	2012	2011
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$—	$4	$2
Interstate transportation and storage	142	120	24
Midstream	—	(9)	—
NGL transportation and services	(2)	2	—
Investment in Sunoco Logistics	18	5	—
Retail marketing	2	1	—
All other	12	19	—
Total equity in earnings of unconsolidated affiliates	$172	$142	$26

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	Years Ended December 31,		
	2013	2012	2011
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$464	$601	$667
Interstate transportation and storage	1,269	1,013	373
Midstream	479	467	421
NGL transportation and services	351	209	127
Investment in Sunoco Logistics	871	219	—
Retail marketing	325	109	—
All other	194	126	193
Total Segment Adjusted EBITDA	3,953	2,744	1,781
Depreciation and amortization	(1,032)	(656)	(405)
Interest expense, net of interest capitalized	(849)	(665)	(474)
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Goodwill impairment	(689)	—	—
Gains (losses) on interest rate derivatives	44	(4)	(77)
Non-cash unit-based compensation expense	(47)	(42)	(38)
Unrealized gains (losses) on commodity risk management activities	51	(9)	(11)
LIFO valuation adjustments	3	(75)	—
Loss on extinguishment of debt	—	(115)	—
Non-operating environmental remediation	(168)	—	—
Adjusted EBITDA related to discontinued operations	(76)	(99)	(23)
Adjusted EBITDA related to unconsolidated affiliates	(629)	(480)	(56)
Equity in earnings of unconsolidated affiliates	172	142	26
Other, net	12	22	(4)
Income from continuing operations before income tax expense	$832	$1,820	$719

	December 31,		
	2013	2012	2011
Total assets:			
Intrastate transportation and storage	$4,606	$4,691	$4,785
Interstate transportation and storage	10,988	11,794	3,661
Midstream	3,133	4,946	2,513
NGL transportation and services	4,326	3,765	2,360
Investment in Sunoco Logistics	11,650	10,291	—
Retail marketing	3,936	3,926	—
All other	5,063	3,817	2,200
Total	$43,702	$43,230	$15,519

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	Years Ended December 31,		
	2013	2012	2011
Additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate transportation and storage	$47	$37	$53
Interstate transportation and storage	152	133	207
Midstream	565	1,317	837
NGL transportation and services	443	1,302	325
Investment in Sunoco Logistics	1,018	139	—
Retail marketing	176	58	—
All other	54	63	62
Total	$2,455	$3,049	$1,484

	December 31,		
	2013	2012	2011
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$1	$2	$1
Interstate transportation and storage	2,040	2,142	173
Midstream	—	1	—
NGL transportation and services	29	29	27
Investment in Sunoco Logistics	125	118	—
Retail marketing	22	21	—
All other	2,219	1,189	—
Total	$4,436	$3,502	$201

15. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts. ETC OLP's business is also seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

	Quarter Ended				
	March 31	June 30	September 30	December 31	Total Year
2013:					
Revenues	$10,854	$11,551	$11,902	$12,032	$46,339
Gross profit	1,260	1,322	1,248	1,305	5,135
Operating income (loss)	534	632	526	(151)	1,541
Net income (loss)	424	413	404	(473)	768
Limited Partners' interest in net income (loss)	194	165	209	(666)	(98)
Basic net income (loss) per limited partner unit	$0.63	$0.53	$0.55	$(1.90)	$(0.18)
Diluted net income (loss) per limited partner unit	$0.63	$0.53	$0.55	$(1.90)	$(0.18)

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The three months ended December 31, 2013 was impacted by ETP’s recognition of a goodwill impairment of $689 million. For the three months ended December 31, 2013, distributions paid for the period exceeded net income attributable to partners by $1.12 billion. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.

	Quarter Ended				
	March 31	June 30	September 30	December 31	Total Year
2012:					
Revenues	$1,323	$1,596	$1,802	$10,981	$15,702
Gross profit	542	797	776	1,321	3,436
Operating income	209	357	365	463	1,394
Net income	1,088	135	64	361	1,648
Limited Partners’ interest in net income (loss)	998	2	(80)	188	1,108
Basic net income (loss) per limited partner unit	$4.36	$0.00	$(0.33)	$0.62	$4.43
Diluted net income (loss) per limited partner unit	$4.35	$0.00	$(0.33)	$0.62	$4.42

For the three months ended September 30, 2012, distributions paid for the period exceeded net income attributable to partners by $356 million. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period. In addition, for the three months ended June 30, 2012 distributions paid for the period exceeded net income attributable to partners by $223 million. The allocation of the distributions in excess of net income is based on the proportionate ownership interests of the Limited Partners and General Partner. Based on this allocation approach, net income per Limited Partner unit (basic and diluted) for the three months ended June 30, 2012 was approximately zero, after taking into account distributions to be paid with respect to incentive distribution rights and employee unit awards.