DAKOTA ACCESS, LLC

APPLICATION FOR CERTIFICATE IN GOOD STANDING

EXHIBIT I
ETE Financial Statements

(Part 2 of 2)

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

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.

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.

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.

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.

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.

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.

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.

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.

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.

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 Measurements at December 31, 2013	
	Fair Value Total	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)

	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

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.

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.

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

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

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.

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.

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.

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

	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

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.

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.

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.

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

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
Repurchase 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."

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

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.

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, E TE 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

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.

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.

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.

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.

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.

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.

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

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

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.

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

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

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.

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

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:

			Notional Amount Outstanding	
Entity	Term	Type[1]	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. 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. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

(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.

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:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	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.

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

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.

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

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

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.

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.

	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:

Years	Pension Benefits		Other Postretirement Benefits (Gross, Before Medicare Part D)
	Funded Plans	Unfunded Plans	
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

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;

- 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.

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

	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

	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

	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)

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.

3. ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES CONSOLIDATED FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Report of Independent Registered Public Accounting Firm	S - 81
Consolidated Balance Sheets – December 31, 2013 and 2012	S - 82
Consolidated Statements of Operations – Years Ended December 31, 2013, 2012 and 2011	S - 84
Consolidated Statements of Comprehensive Income – Years Ended December 31, 2013, 2012 and 2011	S - 85
Consolidated Statements of Equity – Years Ended December 31, 2013, 2012 and 2011	S - 86
Consolidated Statements of Cash Flows – Years Ended December 31, 2013, 2012 and 2011	S - 87
Notes to Consolidated Financial Statements	S - 89

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners GP, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners GP, 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. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 GP, 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.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

ENERGY TRANSFER PARTNERS GP, 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	4,758	5,635
INTANGIBLE ASSETS, net	1,568	1,561
OTHER NON-CURRENT ASSETS, net	766	357
Total assets	$ 43,731	$ 43,259

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

ENERGY TRANSFER PARTNERS GP, 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	—	—
Limited Partners:		
Class A Limited Partner interest	71	86
Class B Limited Partner interest	129	131
Total partners' capital	200	217
Noncontrolling interest	16,117	17,144
Total equity	16,317	17,361
Total liabilities and equity	$ 43,731	$ 43,259

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

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

	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	262	1,187	264
NET INCOME ATTRIBUTABLE TO PARTNERS	506	461	433
GENERAL PARTNER'S INTEREST IN NET INCOME	—	—	—
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 506	$ 461	$ 433

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

ENERGY TRANSFER PARTNERS GP, 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	341	1,162	244
Comprehensive income attributable to partners	$ 506	$ 461	$ 433

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

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

	General Partner	Limited Partners	Noncontrolling Interest	Total
Balance, December 31, 2010	$ —	$ 204	$ 4,568	$ 4,772
Distributions to partners	—	(426)	—	(426)
Distributions to noncontrolling interest	—	—	(777)	(777)
ETP units issued for cash	—	—	1,467	1,467
Capital contributions from noncontrolling interest	—	—	645	645
ETP issuance of units in acquisitions	—	—	3	3
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	—	30 30	30
Other comprehensive loss, net of tax	—	—	(20)	(20)
Other, net	—	—	(12)	(12)
Net income	—	433	264	697
Balance, December 31, 2011	—	211	6,168	6,379
Distributions to partners	—	(454)	—	(454)
Distributions to noncontrolling interest	—	—	(1,122)	(1,122)
ETP units issued for cash	—	—	791	791
Capital contributions from noncontrolling interest	—	—	343	343
Sunoco Merger (see Note 3)	—	—	5,868	5,868
Holdco Transaction (see Note 3)	—	—	3,913	3,913
Issuance of ETP units in other acquisitions (excluding Sunoco)	—	—	7	7
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	—	27	27
Other comprehensive loss net of tax	—	—	(25)	(25)
Other, net	—	(1)	(13)	(14)
Net income	—	461	1,187	1,648
Balance, December 31, 2012	—	217	17,144	17,361
Distributions to partners	—	(523)	—	(523)
Distributions to noncontrolling interest	—	—	(1,661)	(1,661)
ETP units issued for cash	—	—	1,611	1,611
Capital contributions from noncontrolling interest	—	—	137	137
Holdco Acquisition and SUGS Contribution (see Note 3)	—	—	(1,440)	(1,440)
Other comprehensive income, net of tax	—	—	79	79
Other, net	—	—	(15)	(15)
Net income	—	506	262	768
Balance, December 31, 2013	$ —	$ 200	$ 16,117	$ 16,317

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

ENERGY TRANSFER PARTNERS GP, 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	—
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	2,385	1,206	1,352
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)

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 ETP Limited Partner units	1,611	791	1,467
Capital contributions received from noncontrolling interest	147	320	645
Distributions to partners	(523)	(454)	(426)
Distributions to noncontrolling interest	(1,673)	(1,130)	(785)
Debt issuance costs	(32)	(20)	(20)
Other	(36)	—	—
Net cash provided by financing activities	313	1,283	2,258
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.

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

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners GP, L.P. ("ETP GP" or "the Partnership") was formed in August 2000 as a Delaware limited partnership. ETP GP is the General Partner and the owner of the general partner interest of Energy Transfer Partners, L.P., a publicly traded master limited partnership ("ETP"). ETP GP is owned 99.99% by its limited partners, and 0.01% by its general partner, Energy Transfer Partners, L.L.C. ("ETP LLC").

Energy Transfer Equity, L.P. ("ETE") is the 100% owner of ETP LLC and also owns 100% of our Class A and Class B Limited Partner interests. For more information on our Class A and Class B Limited Partner interests, see Note 6.

Financial Statement Presentation

The consolidated financial statements and notes thereto of ETP GP and its subsidiaries presented herein for the years ended December 31, 2013, 2012 and 2011, have been prepared in accordance with GAAP. 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 February 27, 2014, 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.

In October 2012, we sold Canyon and the results of continuing operations of Canyon have been reclassified to income (loss) from discontinued operations. 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, our 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).

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.

- 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, that sell gasoline and middle distillates and operate convenience stores primarily on the east coast and in the midwest region of the United States.

The Partnership, ETP, the Operating Companies and their subsidiaries are collectively described in this report as "we," "us," "our," "ETP," "Energy Transfer" or the "Partnership."

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.

Our intrastate transportation and storage and interstate transportation and storage operations' 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 operations 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 operations 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 operations 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 operations, 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 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 operations 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 operations are subject to regulation by certain state and federal authorities, and certain subsidiaries in those operations 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 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.

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 ETP common units in connection with certain acquisitions	$ —	$ 2,295	$ 3
Issuance of ETP Common Units in connection with the Holdco Acquisition	$ 2,464	$ —	$ —
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.

Sunoco Logistics 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 operations 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.

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.

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	568
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	77
Right of way (20 to 83 years)	1,901	2,042
Furniture and fixtures (2 to 25 years)	48	48
Linepack	116	116
Pad gas	52	58
Other (1 to 48 years)	626	986
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 operations and during the fourth quarter for subsidiaries in our interstate transportation and storage, NGL transportation and services, and retail marketing operations and all others. We recorded goodwill impairments for the periods presented in these consolidated financial statements.

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	ETP GP	Total
Balance, December 31, 2011	$ 10	$ 99	$ 37	$ 432	$ —	$ —	$ 642	$ 29	$ 1,249
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	29	5,635
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	29	$ 4,758

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.

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.

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 the 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.

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.

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 Measurements at December 31, 2013	
	Fair Value Total	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)

	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

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 operation 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 ETP's retail marketing operations were $2.22 billion and $573 million for the years ended December 31, 2013 and 2012, respectively.

Income Taxes

ETP GP 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 the Partnership Agreement.

As a limited partnership, ETP is subject to a statutory requirement that its "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of its total gross income, determined on a calendar year basis. If ETP's 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, ETP's 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.

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.

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

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

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).

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.

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. 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.

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 operations. Regency's 30% interest in Lone Star is reflected as noncontrolling interest.

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 ETP's investment in Regency was $1.41 billion as of December 31, 2013.

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.

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. 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.

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	$ 1,379	$ 878
Property, plant and equipment, net	12,313	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

	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. 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
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
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.

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.

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.

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, 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 ETP's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt. The ETP Credit Facility provides temporary financing for growth projects, as well as for general partnership purposes.

In November 2013, ETP 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.

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 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.

6. EQUITY:

Limited Partner interests are represented by Class A Units and Class B Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Class B Units constitute a profits interest in ETP GP and will only receive allocations of income, gain, loss deduction and credit and their pro rata share of cash distributions from ETP GP attributable to the ownership of ETP's IDRs. Under our Partnership Agreement, after giving effect to the special allocation of net income to our Class B Units for their profits interest, net income is allocated among the Partners as follows:

- First, 100% to our General Partner, until the aggregate net income allocated to our General Partner for the current year and all previous years is equal to the aggregate net losses allocated to our General Partner for all previous years;
- Second, 99.99% to our Class A Limited Partners, in proportion to their relative allocation of net losses, and 0.01% to our General Partner until the aggregate net income allocated to our Class A Limited Partners and our General Partner for the current and all previous years is equal to the aggregate net losses allocated to our Class A Limited Partners and our General Partner for all previous years; and
- Third, 99.99% to our Class A Limited Partners, pro rata, and 0.01% to our General Partner.

Common Units Activity by ETP

The change in ETP 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
Repurchase 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

ETP's Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of an ETP Common Unit is entitled to one vote per unit on all matters presented to the ETP Limited Partners for a vote. In addition, if at any time any person or group (other than ETP's General Partner and its affiliates) owns beneficially 20% or more of all ETP Common Units, any ETP 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 ETP 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 ETP Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash. "

ETP Class G Units

In conjunction with the Sunoco Merger, ETP amended their partnership agreement to create the ETP Class F Units. The number of ETP Class F Units issued was determined at the closing of the Sunoco Merger and equaled 90.7 million, which included 40 million ETP 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 ETP Class F Units generally did not have any voting rights. The ETP Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by ETP and its subsidiaries, other than Holdco, and available for distribution, up to a maximum of $3.75 per Class F Unit per year. In April 2013, all of the outstanding ETP Class F Units were exchanged for ETP Class G Units on a one-for-one basis. The ETP Class G Units have terms that are substantially the same as the ETP Class F Units, with the principal difference between the ETP Class G Units and the ETP Class F Units being that allocations of depreciation and amortization to the ETP Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss.

ETP 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 ETP 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 "ETP 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 ETP 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 ETP 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.

Sale of Common Units by ETP

The following table summarizes ETP's 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.

ETP's Equity Distribution Program

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

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

Quarterly Distribution of Available Cash

Our distributions policy is consistent with the terms of the Partnership Agreement, which require that we distribute all of our available cash quarterly. Our only cash-generating assets consist of partnership interests, including IDRs, from which we receive quarterly distributions from ETP. We have no independent operations outside of our interests in ETP. Under the Partnership Agreement, our distributions are characterized as the GP Distribution Amount and the IDR Distribution Amount. The GP Distribution Amount is all distributions we receive from ETP with respect to our General Partner Interest and the IDR Distribution Amount is all distributions received from ETP with respect to the IDR. Within 45 days following the end of each quarter, we will distribute all of our GP Available Cash and IDR Available Cash, as defined in the Partnership Agreement. GP Available Cash shall be distributed 99.99% to the Class A Limited Partners, pro rata and 0.01% to the General partner. IDR Available Cash shall be distributed 99.99% to the Class B Limited Partners, pro rata and 0.01% to the General Partner.

ETP GP has the right, in connection with the issuance of any equity security by ETP, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in ETP as ETP GP and its affiliates owned immediately prior to such issuance.

Contributions to Subsidiary

The Parent Company indirectly owns the entire general partner interest in ETP through its ownership of ETP GP, the general partner of ETP. ETP GP has the right, but not the obligation, to contribute a proportionate amount of capital to ETP to maintain its current general partner interest. ETP GP's interest in ETP's distributions is reduced if ETP issues additional units and ETP GP does not contribute a proportionate amount of capital to ETP to maintain its General Partner interest.

ETP's Quarterly Distributions of Available Cash

ETP's Partnership Agreement requires that ETP distribute all of its Available Cash to its Unitholders and its 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 ETP's 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 ETP General Partner (ETP GP) in its sole discretion to provide for the proper conduct of ETP's business, to comply with applicable laws or any debt instrument or other agreement, or to provide

funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in the ETP Partnership Agreement.

ETP's 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 the General Partner are determined based on the amount by which quarterly distribution to ETP common Unitholders exceed certain specified target levels, as set forth in the ETP Partnership Agreement.

ETP 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, E TE 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 ETP Class H Units, which are referred to in "ETP Class H Units" above, were intended to offset a portion of the incentive distribution relinquishments previously granted by ETE to ETP. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the incremental distributions on the ETP 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 ETP Class H Units are fixed amounts for each quarter for which the incentive distribution relinquishments and incremental distributions on the ETP Class H Units are in effect.

In addition to the amounts above, in connection with the ETP's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of IDRs in $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 ETP 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

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	(61)	19
Total AOCI, net of tax	$ —	$ —

7. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

ETP has 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, 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 its equity incentive plans.

ETP Unit Grants

ETP has granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting contingent on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common

Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its common units promptly following each such distribution by ETP to its unitholders. These rights as "distribution equivalent rights." Under ETP's equity incentive plans, ETP's non-employee directors each receive grants with a five-year service vesting requirement.

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.

8. 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.

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.

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.

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

FERC Audit

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

Contingent 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.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2014	$	80
2015		78
2016		70
2017		66
2018		53
Thereafter		42
Future minimum lease commitments		389
Less: Sublease rental income		(57)
Net future minimum lease commitments	$	332

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

Litigation and Contingencies

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

Sunoco Litigation

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

Litigation Relating to the Southern Union Merger

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

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

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

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

MTBE Litigation

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

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.

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

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.

10. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

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

physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage operations and operational gas sales on our interstate transportation and storage operations. 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 operations 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 operations 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 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 operations 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 operations, 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 operations 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.

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

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:

			Notional Amount Outstanding	
Entity	Term	Type[1]	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.

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:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	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.

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)

11. 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

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.

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

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

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.

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.

	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 costs 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:

Years	Pension Benefits		Other Postretirement Benefits (Gross, Before Medicare Part D)
	Funded Plans	Unfunded Plans	
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.

12. RELATED PARTY TRANSACTIONS:

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

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

Sunoco Logistics has an agreement with PES relating to the Fort Mifflin Terminal Complex. Under this agreement, PES will deliver an average of 300,000 Bbls/d of crude oil and refined products per contract year at the Fort Mifflin facility. PES does

not have exclusive use of the Fort Mifflin Terminal Complex; however, Sunoco Logistics is obligated to provide the necessary tanks, marine docks and pipelines for PES to meet its minimum requirements under the agreement. Sunoco Logistics 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 in June 2013, 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

13. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of ETP GP, which are included to provide additional information with respect to ETP GP's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS

	December 31,	
	2013	2012
ASSETS		
INVESTMENT IN ENERGY TRANSFER PARTNERS	$ 171	$ 188
GOODWILL	29	29
Total assets	$ 200	$ 217
LIABILITIES AND EQUITY		
EQUITY:		
General Partner	$ —	$ —
Limited Partners:		
Class A Limited Partner interest	70	86
Class B Limited Partner interest	130	131
Total partners' capital	200	217
Total liabilities and equity	$ 200	$ 217

STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2013	2012	2011
OTHER INCOME (EXPENSE):			
Equity in earnings of unconsolidated affiliates	$ 506	$ 461	$ 433
NET INCOME BEFORE INCOME TAX EXPENSE	506	461	433
Income tax expense	—	—	—
NET INCOME	$ 506	$ 461	$ 433

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2013	2012	2011
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 523	$ 454	$ 426
CASH FLOWS FROM FINANCING ACTIVITIES:			
Distributions to partners	(523)	(454)	(426)
Net cash used in financing activities	(523)	(454)	(426)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	—	—	—
CASH AND CASH EQUIVALENTS, beginning of period	—	—	—
CASH AND CASH EQUIVALENTS, end of period	$ —	$ —	$ —

4. REGENCY ENERGY PARTNERS LP FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Report of Independent Registered Public Accounting Firm	S - 145
Consolidated Balance Sheets – December 31, 2013 and 2012	S - 146
Consolidated Statements of Operations – Years Ended December 31, 2013, 2012 and 2011	S - 147
Consolidated Statements of Comprehensive Income – Years Ended December 31, 2013, 2012 and 2011	S - 148
Consolidated Statements of Partners' Capital and Noncontrolling Interest – Years Ended December 31, 2013, 2012 and 2011	S - 149
Consolidated Statements of Cash Flows – Years Ended December 31, 2013, 2012 and 2011	S - 150
Notes to Consolidated Financial Statements	S - 151

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency Energy Partners LP

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' capital and noncontrolling interest 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 financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Partnership's investment in which is accounted for under the equity method of accounting. The Partnership's investment in Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 was $548 million and $581 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $39 million, $42 million, and $43 million, respectively, for each of the three years in the period ended December 31, 2013. Those statements were audited by other auditors, whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the reports of the other auditors.

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

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency Energy Partners LP 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.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control, which has been accounted for in a manner similar to a pooling of interests.

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 (not separately included herein) expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Table of Contents

Regency Energy Partners LP

Consolidated Balance Sheets
(in millions except unit data)

	December 31,	
	2013	2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 53
Trade accounts receivable	292	222
Related party receivables	28	8
Inventories	42	27
Other current assets	19	30
Total current assets	400	340
Property, Plant and Equipment:		
Gathering and transmission systems	1,671	1,308
Compression equipment	1,627	1,326
Gas plants and buildings	825	568
Other property, plant and equipment	414	377
Construction-in-progress	513	507
Total property, plant and equipment	5,050	4,086
Less accumulated depreciation	(632)	(400)
Property, plant and equipment, net	4,418	3,686
Other Assets:		
Investments in unconsolidated affiliates	2,097	2,214
Other, net of accumulated amortization of debt issuance costs of $24 and $17	57	43
Total other assets	2,154	2,257
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $107 and $77	682	712
Goodwill	1,128	1,128
Total intangible assets and goodwill	1,810	1,840
TOTAL ASSETS	$ 8,782	$ 8,123
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 26	$ 10
Trade accounts payable	291	255
Related party payables	69	95
Accrued interest	38	30
Other current liabilities	51	99
Total current liabilities	475	489
Long-term derivative liabilities	19	25
Other long-term liabilities	30	39
Long-term debt, net	3,310	2,157
Commitments and contingencies		
Series A Preferred Units, redemption amount of $38 and $85	32	73
Partners' Capital and Noncontrolling Interest:		
Common units (214,287,955 and 174,574,175 units authorized; 210,850,232 and 170,951,457 units issued and outstanding at December 31, 2013 and 2012)	3,886	3,207
Class F common units (6,274,483 and 0 units authorized, issued and outstanding at December 31, 2013 and 2012)	146	—
General partner interest	782	326
Predecessor equity	—	1,733
Accumulated other comprehensive loss	—	(3)
Total partners' capital	4,814	5,263
Noncontrolling interest	102	77
Total partners' capital and noncontrolling interest	4,916	5,340
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 8,782	$ 8,123

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Operations
(in millions except unit data and per unit data)

	Years Ended December 31,		
	2013	2012	2011
REVENUES			
Gas sales, including related party amounts of $71, $42, and $23	$ 826	$ 508	$ 456
NGL sales, including related party amounts of $81, $28, and $365	1,053	991	603
Gathering, transportation and other fees, including related party amounts of $26, $29, and $24	545	401	351
Net realized and unrealized (loss) gain from derivatives	(8)	23	(19)
Other, including related party amounts of $-, $1, and $10	105	77	43
Total revenues	2,521	2,000	1,434
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $56, $35, and $22	1,793	1,387	1,013
Operation and maintenance	296	228	147
General and administrative, including related party amounts of $11, $15, and $17	88	100	67
Loss (gain) on asset sales, net	2	3	(2)
Depreciation and amortization	287	252	169
Total operating costs and expenses	2,466	1,970	1,394
OPERATING INCOME	55	30	40
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29	17
INCOME BEFORE INCOME TAXES	26	34	74
Income tax benefit	(1)	—	—
NET INCOME	$ 27	$ 34	$ 74
Net income attributable to noncontrolling interest	(8)	(2)	(2)
NET INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 19	$ 32	$ 72
Amounts attributable to Series A preferred units	6	10	8
General partner's interest, including IDRs	11	9	7
Beneficial conversion feature for Class F units	4	—	—
Pre-acquisition loss from SUGS allocated to predecessor equity	(36)	(14)	—
Limited partners' interest in net income	$ 34	$ 27	$ 57
Basic and diluted income per common unit:			
Amount allocated to common units	$ 34	$ 27	$ 57
Weighted average number of common units outstanding	196,227,348	167,492,735	145,490,869
Basic income per common unit	$ 0.17	$ 0.16	$ 0.39
Diluted income per common unit	$ 0.17	$ 0.13	$ 0.32
Distributions per common unit	$ 1.87	$ 1.84	$ 1.81
Amount allocated to Class F units due to beneficial conversion feature	$ 4	$ —	$ —
Total number of Class F units outstanding	6,274,483	—	—
Income per Class F unit due to beneficial conversion feature	$ 0.72	$ —	$ —

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Comprehensive Income
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 27	$ 34	$ 74
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	6	19
Change in fair value of cash flow hedges	—	(4)	(13)
Total other comprehensive income	$ —	$ 2	$ 6
Comprehensive income	$ 27	$ 36	$ 80
Comprehensive income attributable to noncontrolling interest	8	2	2
Comprehensive income attributable to Regency Energy Partners LP	$ 19	$ 34	$ 78

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in millions)

	Regency Energy Partners LP						
	Common Units	Class F Common Units	General Partner Interest	Predecessor Equity	AOCI	Noncontrolling Interest	Total
Balance—December 31, 2010	$ 2,941	$ —	$ 333	$ —	$ (11)	$ 31	$ 3,294
Common unit offerings, net of costs	436	—	—	—	—	—	436
Unit-based compensation expenses	3	—	—	—	—	—	3
Partner distributions	(264)	—	(10)	—	—	—	(274)
Net income	65	—	7	—	—	2	74
Distributions to Series A Preferred Units	(8)	—	—	—	—	—	(8)
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	19	—	19
Net change in fair value of cash flow hedges	—	—	—	—	(13)	—	(13)
Balance—December 31, 2011	$ 3,173		$ 330	$ —	$ (5)	$ 33	$ 3,531
Common unit offerings, net of costs	297	—	—	—	—	—	297
Issuance of common units under equity distribution program, net of costs	15	—	—	—	—	—	15
Common units issued under LTIP, net of forfeitures and tax withholding	(1)	—	—	—	—	—	(1)
Unit-based compensation expenses	5	—	—	—	—	—	5
Partner distributions	(309)	—	(13)	—	—	—	(322)
Net income (loss)	37	—	9	(14)	—	2	34
Contributions from noncontrolling interest	—	—	—	—	—	42	42
Distributions to Series A Preferred Units	(8)	—	—	—	—	—	(8)
Accretion of Series A Preferred Units	(2)	—	—	—	—	—	(2)
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	5	—	5
Contribution of net investment to unitholders	—	—	—	1,747	(3)	—	1,744
Balance—December 31, 2012	$ 3,207	$ —	$ 326	$ 1,733	$ (3)	$ 77	$ 5,340
Contribution of net investment to the Partnership	—	—	1,925	(1,928)	3	—	—
Issuance of common units in connection with the SUGS Acquisition, net of costs	819	—	(819)	—	—	—	—
Issuance of Class F common units in connection with the SUGS Acquisition, net of costs	—	142	(142)	—	—	—	—
Contribution of assets between entities under common control below historical cost	—	—	(504)	231	—	—	(273)
Issuance of common units under equity distribution program, net of costs	149	—	—	—	—	—	149
Conversion of Series A Preferred Units for common units	41	—	—	—	—	—	41
Unit-based compensation expenses	7	—	—	—	—	—	7
Partner distributions and distributions on unvested unit awards	(371)	—	(15)	—	—	—	(386)
Contributions from noncontrolling interest	—	—	—	—	—	17	17
Net income (loss)	40	4	11	(36)	—	8	27
Distributions to Series A Preferred Units	(6)	—	—	—	—	—	(6)
Balance—December 31, 2013	$ 3,886	$ 146	$ 782	$ —	$ —	$ 102	$ 4,916

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Cash Flows
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net income	$ 27	$ 34	$ 74
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	293	259	175
Income from unconsolidated affiliates	(135)	(105)	(120)
Derivative valuation changes	6	(12)	(21)
Loss (gain) on asset sales, net	2	3	(2)
Unit-based compensation expenses	7	5	3
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	(96)	—	(8)
Other current assets and other current liabilities	(54)	10	11
Trade accounts payable, related party payables and deferred revenues	119	18	23
Distributions of earnings received from unconsolidated affiliates	142	121	119
Cash flow changes in other assets and liabilities	125	(9)	—
Net cash flows provided by operating activities	436	324	254
INVESTING ACTIVITIES			
Capital expenditures	(1,034)	(560)	(406)
Capital contributions to unconsolidated affiliates	(148)	(356)	(53)
Distributions in excess of earnings of unconsolidated affiliates	249	83	74
Acquisition of investment in unconsolidated affiliates, net of cash received	—	—	(594)
Acquisitions, net of cash received	(475)	—	—
Proceeds from asset sales	15	26	24
Net cash flows used in investing activities	(1,393)	(807)	(955)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	318	(140)	47
Proceeds from issuance of senior notes	1,000	700	500
Redemptions of senior notes	(163)	(88)	—
Debt issuance costs	(24)	(15)	(10)
Partner distributions and distributions on unvested unit awards	(386)	(322)	(274)
Contributions from noncontrolling interest	17	42	—
Contributions from previous parent	—	51	—
Drafts payable	18	4	2
Common units issued under LTIP, net of forfeitures and tax withholding	—	(1)	—
Common unit offerings, net of issuance costs	—	297	436
Common units issued under equity distribution program, net of costs	149	15	—
Distributions to Series A Preferred Units	(6)	(8)	(8)
Net cash flows provided by financing activities	923	535	693
Net change in cash and cash equivalents	(34)	52	(8)
Cash and cash equivalents at beginning of period	53	1	9
Cash and cash equivalents at end of period	$ 19	$ 53	$ 1
Supplemental cash flow information:			
Accrued capital expenditures	$ 60	$ 136	$ 24
Issuance of Class F and common units in connection with SUGS Acquisition	961	—	—
Interest paid, net of amounts capitalized	146	112	83
Income taxes paid	—	—	2
Accrued capital contribution to unconsolidated affiliate	13	23	—

See accompanying notes to consolidated financial statements

Regency Energy Partners LP
Notes to Consolidated Financial Statements
(Tabular dollar amounts, except unit and per unit data, are in millions)

1. Organization and Basis of Presentation

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries (the "Partnership"), a Delaware limited partnership. The Partnership was formed on September 8, 2005, and completed its IPO on February 3, 2006. The Partnership and its subsidiaries are engaged in the business of gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. Regency GP LP is the Partnership's general partner and Regency GP LLC is the managing general partner of the Partnership and the general partner of Regency GP LP.

SUGS Acquisition. In April 2013, the Partnership acquired SUGS from Southern Union, a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 of common units and 6,274,483 Class F common units. The Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the net proceeds of $600 million of senior notes issued by the Partnership on April 30, 2013 in a private placement. In December 2013, these senior notes were exchanged for senior notes that are substantially identical, except that the exchange senior notes are registered under federal securities law and do not have any transfer restrictions. In January 2014, Panhandle Eastern Pipe Line Company, LP ("PEPL") entered into an agreement and plan of merger with Southern Union and PEPL Holdings, pursuant to which each of Southern Union and PEPL Holdings were merged with and into PEPL, with PEPL as the surviving entity. In connection with this merger, PEPL assumed the guarantee of collection with respect to the payment of the principal amounts of the senior notes issued.

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began). The SUGS Acquisition does not impact historical earnings per unit as pre-acquisition earnings were allocated to predecessor equity.

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

	April 30, 2013
Current assets	$ 113
Property, plant and equipment, net	1,608
Goodwill	337
Other non-current assets	1
Total assets acquired	$ 2,059
Less:	
Current liabilities	(93)
Non-current liabilities	(36)
Net assets acquired	$ 1,930

The following table presents the revenues and net income for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS [1]	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS [1]	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

Basis of presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending upon the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

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

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of ETP. As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with 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.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

Earnings per Unit. Basic net income per common unit is computed through the use of the two-class method, which allocates earnings to each class of equity security based on their participation in distributions and deemed distributions. Accretion of the Series A Preferred Units is considered as deemed distributions. Distributions and deemed distributions to the Series A Preferred Units reduce the amount of net income available to the general partner and limited partner interests. The general partners' interest in net income or loss consists of its respective percentage interest, make-whole allocations for any losses allocated in a prior tax year and IDRs. After deducting the General Partner's interest, the limited partners' interest in the remaining net income or loss is allocated to each class of equity units based on distributions and beneficial conversion feature amounts, if applicable, then divided by the weighted average number of common and subordinated units outstanding in each class of security. Diluted net income per common unit is computed by dividing limited partners' interest in net income, after deducting the General Partner's interest, by the weighted average number of units outstanding and the effect of non-vested phantom units, Series A Preferred Units and unit options. For special classes of common units, such as the Class F units issued with a beneficial conversion feature, the amount of the benefit associated with the period is added back to net income and the unconverted class is added to the denominator.

3. Partners' Capital and Distributions

Units Activity. The changes in common and Class F units were as follows:

	Common	Class F
Balance - December 31, 2010	137,281,336	—
Common unit offerings, net of costs	20,000,001	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	156,271	—
Balance - December 31, 2011	157,437,608	—
Common unit offerings, net of costs	12,650,000	—
Issuance of common units under the equity distribution agreement, net of cost	691,129	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	172,720	—
Balance - December 31, 2012	170,951,457	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	184,995	—
Issuance of common units under the equity distribution agreement, net of cost	5,712,138	—
Conversion of Series A preferred units for common units	2,629,223	—
Issuance of common units and Class F common units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - December 31, 2013	210,850,232	6,274,483

(1) ETE has agreed to forgo IDR payments on the Partnership common units issued with the SUGS Acquisition for twenty-four months post-transaction closing.
(2) The Class F common units are not entitled to participate in the Partnership's distributions or earnings for twenty-four months post-transaction closing.

Equity Distribution Agreement. In June 2012, the Partnership entered into an Equity Distribution Agreement with Citi under which the Partnership may offer and sell common units, representing limited partner interests, having an aggregate offering price of up

to $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Citi. The Partnership may also sell common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Citi as principal would be pursuant to the terms of a separate agreement between the Partnership and Citi. The Partnership intends to use the net proceeds from the sale of these units for general partnership purposes. For the years ended December 31, 2013 and 2012, the Partnership received net proceeds of $149 million and $15 million, respectively, from units issued pursuant to this Equity Distribution Agreement. As of December 31, 2013, $34 million remains available to be issued under this agreement.

Public Common Unit Offerings. In March 2012, the Partnership issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $297 million. In May 2012, the Partnership used the net proceeds from this offering to redeem 35%, or $88 million, in aggregate principal amounts of its outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under the revolving credit facility. In August 2010, the Partnership sold 17,537,500 common units and received $408 million in proceeds, inclusive of the General Partner's proportionate capital contribution. In October 2011, the Partnership issued 11,500,000 common units representing limited partnership interests in a public offering at a price of $20.92 per common unit, resulting in net proceeds of $232 million which were used to repay outstanding borrowings under the revolving credit facility.

Private Common Unit Offerings. In May 2011, the Partnership sold 8,500,001 common units representing limited partnership interests resulting in net proceeds of $204 million, to partially fund its capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

Beneficial Conversion Feature. The Partnership issued 6,274,483 Class F common units in connection with the SUGS Acquisition. At the commitment date (February 27, 2013), the sales price of $23.91 per unit represented a $2.19 per unit discount from the fair value of the Partnership's common units as of April 30, 2013. Under FASB ASC 470-20, "*Debt with Conversion and Other Options*," the discount represents a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class F common units are outstanding, as indicated on the statement of operations in the line item entitled "beneficial conversion feature for Class F common units." The Class F common units are convertible to common units on a one-for-one basis on May 8, 2015.

Noncontrolling Interest. The Partnership operates ELG, a gas gathering joint venture in south Texas in which other third party companies own a 40% interest, which is reflected on the Partnership's consolidated balance sheet as noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The General Partner is entitled to its proportionate share of all quarterly distributions that the Partnership makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2% interest in these distributions has been reduced since the Partnership has issued additional units and the General Partner has not contributed a proportionate amount of capital to the Partnership to maintain its General Partner interest. The General Partner ownership interest as of December 31, 2013 was 1.3%. This General Partner interest is represented by 2,834,381 equivalent units as of December 31, 2013.

The IDRs held by the General Partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's IDRs are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its general partner interest.

In connection with the SUGS Acquisition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing.

Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2013 and 2012:

Distribution Date	Cash Distribution (per common unit)
November 14, 2013	$ 0.470
August 14, 2013	0.465
May 13, 2013	0.460
February 14, 2013	0.460
November 14, 2012	$ 0.460
August 14, 2012	0.460
May 14, 2012	0.460
February 13, 2012	0.460

The Partnership paid a cash distribution of $0.475 per common unit on February 14, 2014.

4. Income per Limited Partner Unit

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the years ended December 31, 2013, 2012, and 2011.

	For the Years Ended December 31,								
	2013			2012			2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income per unit									
Limited Partners' interest in net income	$ 34	196,227,348	$ 0.17	$ 27	167,492,735	$ 0.16	$ 57	145,490,869	$ 0.39
Effect of Dilutive Securities:									
Common unit options	—	22,714		—	10,854		—	19,192	
Phantom units *	—	357,230		—	223,325		—	148,388	
Series A Preferred Units	—	2,050,854		(5)	4,658,700		(10)	4,632,389	
Diluted income per unit	$ 34	198,658,146	$ 0.17	$ 22	172,385,614	$ 0.13	$ 47	150,290,838	$ 0.32

* Amount assumes maximum conversion rate for market condition awards.

There were no securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit.

The partnership agreement requires that the General Partner shall receive a 100% allocation of income until its capital account is made whole for all of the net losses allocated to it in prior years.

5. Acquisitions and Dispositions

2013

SUGS Acquisition. The SUGS Acquisition is discussed in footnote 1 - Organization and Basis of Presentation.

PVR Acquisition. In October 2013, the Partnership announced that it entered into a merger agreement with PVR ("PVR Acquisition") pursuant to which the Partnership intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. In November 2013, the Partnership

received approval of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in March 2014.

The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock's midstream business (the "Eagle Rock Midstream Acquisition") for approximately $1.3 billion. This acquisition is expected to complement the Partnership's core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, east Texas and south Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Hoover Energy Acquisition. On February 3, 2014, the Partnership completed its previously announced acquisition of the subsidiaries of Hoover that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in west Texas. The consideration paid by the Partnership was valued at $281.6 million (subject to customary post-closing adjustments) and consisted of (i) 4,040,471 common units issued to Hoover and (ii) $183.6 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership will account for the acquisition of Hoover 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. Management's evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements.

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star, in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

Ranch JV. On December 2, 2011, Ranch JV was formed by the Partnership, APM and CM, each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.

6. Investments in Unconsolidated Affiliates

As of December 31, 2013, the Partnership has a 49.99% general partner interest in HPC, a 50% membership interest in MEP, a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% membership interest in Grey Ranch. The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011, a 49.9% interest in MEP in May 2010 and a 0.1% interest in MEP in September 2011. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2013 and 2012 is as follows:

	December 31,	
	2013	2012
HPC	$ 442	$ 650
MEP	548	581
Lone Star	1,070	948
Ranch JV	36	35
Grey Ranch	1	—
	$ 2,097	$ 2,214

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013				
	HPC [2]	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 137	$ 2	$ —
Distributions	238	72	79	2	—
Share of net income	36	39	64	1	1
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 343	$ 36	$ —
Distributions	61	75	68	—	—
Share of net income	35	42	44	(1)	(9)
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2011				
	HPC	MEP[3]	Lone Star[4]	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 645	$ —	N/A
Purchase of additional interest	—	1	—	—	N/A
Distributions	65	83	22	—	N/A
Return of investment	—	—	23	—	N/A
Share of net income	55	43	28	—	N/A
Amortization of excess fair value of investment [1]	(6)	—	—	—	N/A

(1) The Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $445 million as of December 31, 2013. The Partnership's contingent obligation with respect to the outstanding borrowings under this facility was $222 million at December 31, 2013.

(3) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(4) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 50% interest in Grey Ranch in March 2012, as part of the SUGS Acquisition in April 2013.

7. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges,

and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (propane, butane, and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2013, the Partnership had an immaterial amount in net hedging gains in AOCI, all of which will be amortized to earnings over the next three months.

As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps with a total notional amount of 4,562,500 MMBtu for 2012. These natural gas price swaps were accounted for as cash flow hedges, with effective portion of changes in their fair value recorded to AOCI and reclassified into revenues in the same period which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2013, the Partnership had $510 million of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership's resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2013 was $4 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2013 and 2012 are detailed below:

	Assets		Liabilities	
	December 31,		December 31,	
	2013	2012	2013	2012
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ —	$ —	$ —	$ 5
Total cash flow hedging instruments	—	—	—	5
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 3	$ 4	$ 9	$ 1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	19	25
Total derivatives	$ 4	$ 5	$ 28	$ 31

The Partnership's statements of operations for the years ended December 31, 2013, 2012 and 2011 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)		
Commodity derivatives		$ —	$ (4)	$ (13)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
Commodity derivatives	Revenue	$ —	$ 6	$ (19)

		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income		
Commodity derivatives	Revenue	$ —	$ (5)	$ —
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Recognized in Income on Derivatives		
Commodity derivatives	Revenue	$ (9)	$ 16	$ —
Embedded derivatives	Other income & deductions	6	14	18
		$ (3)	$ 30	$ 18

8. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31,	
	2013	2012
Senior notes	$ 2,800	$ 1,965
Revolving loans	510	192
Total	3,310	2,157
Less: current portion	—	—
Long-term debt	$ 3,310	$ 2,157
Availability under revolving credit facility:		
Total credit facility limit	$ 1,200	$ 1,150
Revolving loans	(510)	(192)
Letters of credit	(14)	(12)
Total available	$ 676	$ 946

Long-term debt maturities as of December 31, 2013 for each of the next five years are as follows:

Year Ended December 31,	Amount
2014	$ —
2015	—
2016	—
2017	—
2018	600
Thereafter	2,710
Total	$ 3,310

Revolving Credit Facility

In the year ended December 31, 2013, 2012 and 2011 the Partnership borrowed $1.43 billion, $1.56 billion and $940 million, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the

same periods, the Partnership repaid $1.1 billion, $1.70 billion and $893 million, respectively, with proceeds from equity offerings and issuances of senior notes.

In May 2013, RGS entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a "Restricted Subsidiary" structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

The Partnership capitalized $6 million of net loan fees which is being amortized over the remaining term.

The revolving credit facility and the guarantees are senior to the Partnership's and the guarantors' unsecured obligations, to the extent of the value of the assets securing such obligations.

As of December 31, 2013, the Partnership was in compliance in all material respects with all of the financial covenants contained within the new credit agreement.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.625% to 1.50% for base rate loans, 1.625% to 2.50% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.17% and 2.93% as of December 31, 2013 and 2012, respectively.

RGS must pay (i) a commitment fee ranging from 0.30% to 0.45% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.625% to 2.50% per annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.00 for the first eight quarters (after March 2015, an increase is allowed in the permitted total leverage ratio for the first two fiscal quarters following any $50 million or greater acquisition), consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2013 and 2012, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or

- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extension thereof.

In February 2014, RGS entered into the first Amendment to the Sixth Amended and restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the credit agreement.

Senior Notes

In May 2009, the Partnership and Finance Corp. issued $250 million of senior notes that mature on June 1, 2016 (the "2016 Notes"). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $88 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

The Partnership and Finance Corp. have outstanding the following series of senior notes (collectively "Senior Notes"):

- $600 million in aggregate principal amount of our 6.875% senior notes due December 1, 2018 (the "2018 Notes") with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 5.75% senior notes due September 1, 2020 (the "2020 Notes") with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6.5% senior notes due July 15, 2021 (the "2021 Notes") with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5.875% senior notes due March 1, 2022 (the "2022 Notes"), issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5.5% senior notes due April 15, 2023 (the "2023 5.5% Notes") with interest payable semi-annually in arrears on April 15 and October 15; and
- $600 million in aggregate principal amount of our 4.5% senior notes due November 1, 2023 (the "2023 4.5% Notes") with interest payable semi-annually in arrears on May 1 and November 1.

The Senior Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date.

- 2018 Notes - Beginning December 1, 2014 100% may be redeemed at fixed redemption price of 103.438% (December 1, 2015 - 101.719% and December 1, 2016 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5.5% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4.5% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or

after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each note holder of the Senior Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. The Partnership's ability to purchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The existing senior notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody's and Standard & Poor's and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2013, we were in compliance with these covenants.

9. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2012	$ 681	$ 60	$ 741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	655	57	712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	$ 629	$ 53	$ 682

The average remaining amortization periods for customer relations and trade names are 24 and 16 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $30 million.

10. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using observable inputs for similar instruments and incorporate Level 1 and Level 2 inputs. Embedded derivatives related to the Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31,					
	2013			2012		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 2	$ 2	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	2	2	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Natural Gas Liquids	4	4	—	1	1	—
Condensate	1	1	—	—	—	—
Embedded Derivatives in Series A Preferred Units	19	—	19	25	—	25
Total Liabilities	$ 28	$ 9	$ 19	$ 31	$ 6	$ 25

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Series A Preferred Units:

Unobservable Input	December 31, 2013
Credit Spread	4.16%
Volatility	23.71%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2013 and 2012. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2013 and 2012.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2012	$ 39
Change in fair value	(14)
Balance at December 31, 2012	25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	$ 19

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2013 was $2.83 billion and $2.80 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.97 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

11. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2013:

For the year ending December 31,	Operating Lease
2014	$ 3
2015	3
2016	2
2017	2
2018	2
Thereafter	34
Total minimum lease payments	$ 46

Total rent expense for operating leases, including those leases with terms of less than one year, was $11 million, $11 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

12. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

The table below reflects the environmental liabilities recorded in the consolidated balance sheet at December 31, 2013 and 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31,	
	2013	2012
Current	$ 2	$ 5
Noncurrent	6	7
Total environmental liabilities	$ 8	$ 12

The Partnership made expenditures related to environmental remediation of $5 million for the year ended December 31, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

CDM Sales Tax Audit. CDM Resource Management LLC ("CDM"), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, the Partnership is unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, none of which are believed to be potentially material to the Partnership at this time.

13. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner's contribution of $2 million. The Series A Preferred Units are convertible to common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value") and accrued interest. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010.

Holders may elect to convert Series A Preferred Units to common units at any time. In July 2013, certain holders of Series A Preferred Units exercised their right to convert 2,459,017 Series A Preferred Units into common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Series A Preferred Units into common units. As of December 31, 2013, the remaining Series A Preferred Units were convertible into 2,050,854 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership's common unit distributions.

Distributions on the Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Series A Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically

accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Series A Preferred Units, all future distributions on the Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Series A Preferred Unit per quarter, (2) $0.09125 per Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Series A Preferred Units are convertible, at the holder's option, into common units, provided that the holder must request conversion of at least 375,000 Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of common units issuable is equal to the issue price of the Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Series A Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2013, the Series A Preferred Units were convertible to 2,050,854 common units.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the year ended December 31, 2013 and 2012:

	Units	Amount	
Balance at January 1, 2012	4,371,586	$ 71	
Accretion to redemption value	N/A	2	
Balance at December 31, 2012	4,371,586	73	
Series A Preferred Units converted into common units	(2,459,017)	(41)	
Balance at December 31, 2013	1,912,569	$ 32	*

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

14. Related Party Transactions

As of December 31, 2013 and 2012, details of the Partnership's related party receivables and related party payables were as follows:

	December 31,	
	2013	2012
Related party receivables		
HPC	$ 1	$ 1
ETE and its subsidiaries	25	5
Ranch JV	2	2
Total related party receivables	$ 28	$ 8
Related party payables		
HPC	$ 1	$ 1
ETE and its subsidiaries	68	94
Total related party payables	$ 69	$ 95

Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, ETC, the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties. The Operation and Service Agreement Amendment describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $11 million for the year ended December 31, 2013, and $17 million for the years ended December 31, 2012 and 2011.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $63 million, $62 million and $57 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2013 and 2012, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

The Partnership's Gathering and Processing segment, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's Contract Services segment provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's Contract Services segment did not sell compression equipment to a subsidiary of ETP for the year ended December 31, 2013, and sold $1 million for the year ended December 31, 2012. As these transactions are between entities under common control, partners' capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's Contract Services segment purchased compression equipment from a subsidiary of ETP for $95 million and $29 million during the years ended December 31, 2013 and 2012, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2013, 2012, and 2011, the related party general and administrative expenses reimbursed to the Partnership were $18 million, $20 million, and $17 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's Contract Services segment provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with Lone Star. In 2013, the Partnership entered into a nineteen month agreement to sell NGL to Lone Star for approximately $5 million per month. For the year ended December 31, 2013, the Partnership had recorded $26 million in NGL sales under this contract.

Transactions with EPD and its subsidiaries. In January 2012, EPD sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

15. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

		Years Ended December 31,		
	Reportable Segment	2013	2012	2011
Customer				
Customer A	Gathering and Processing	$ 381	$ 367	$ 366
Customer B	Gathering and Processing	362	451	—
Supplier				
Supplier A	Gathering and Processing	164	171	133
Supplier B	Gathering and Processing	185	—	—

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

16. Segment Information

The Partnership has five reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, and Corporate. The reportable segments are as described below:

Gathering and Processing. The Partnership provides "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes ELG and the Partnership's 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The Partnership completed the SUGS Acquisition on April 30, 2013 which was a reorganization of entities under common control. Therefore, the Gathering and Processing segment amounts have been retrospectively adjusted to reflect the SUGS Acquisition beginning March 26, 2012, the date upon which common control began.

Natural Gas Transportation. The Partnership owns a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, a 50% membership interest in MEP, which owns a 500-mile interstate natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

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

Contract Services. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. The Partnership also owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.

Corporate. The Corporate segment comprises the Partnership's corporate assets.

The Partnership accounts for intersegment revenues as if the revenues were to third parties, exclusive of certain cost of capital charges.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the Gathering and Processing and the Natural Gas Transportation segments is defined as total revenues, including service fees, less cost of sales. In the Contract Services segment, segment margin is defined as revenues less direct costs.

Management believes segment margin is an important measure because it directly relates to volume, commodity price changes, revenue generating horsepower and revenue generating gallons per minute. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for its investments in unconsolidated affiliates (HPC, MEP, Lone Star, Ranch JV, and Grey Ranch) because it records its ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

Table of Contents

Results for each period, together with amounts related to each segment are shown below:

	Years Ended December 31,		
	2013	2012	2011
External Revenue			
Gathering and Processing	$ 2,287	$ 1,797	$ 1,226
Natural Gas Transportation	1	1	1
NGL Services	—	—	—
Contract Services	215	183	190
Corporate	18	19	17
Eliminations	—	—	—
Total	$ 2,521	$ 2,000	$ 1,434
Intersegment Revenue			
Gathering and Processing	$ —	$ —	$ —
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	15	21	17
Corporate	—	—	—
Eliminations	(15)	(21)	(17)
Total	$ —	$ —	$ —
Cost of Sales			
Gathering and Processing	$ 1,767	$ 1,373	$ 993
Natural Gas Transportation	—	(1)	(2)
NGL Services	—	—	—
Contract Services	26	15	22
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 1,793	$ 1,387	$ 1,013
Segment Margin			
Gathering and Processing	$ 521	$ 423	$ 233
Natural Gas Transportation	—	2	3
NGL Services	—	—	—
Contract Services	204	189	185
Corporate	18	20	17
Eliminations	(15)	(21)	(17)
Total	$ 728	$ 613	$ 421
Operation and Maintenance			
Gathering and Processing	$ 237	$ 183	$ 98
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	72	66	66
Corporate	1	—	—
Eliminations	(14)	(21)	(17)
Total	$ 296	$ 228	$ 147
Depreciation and Amortization			
Gathering and Processing	$ 186	$ 159	$ 87
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	98	86	78
Corporate	3	7	4
Eliminations	—	—	—

Total	$ 287	$ 252	$ 169

	Years Ended December 31,		
	2013	2012	2011
Income from Unconsolidated Affiliates			
Gathering and Processing	$ 1	$ (10)	$ —
Natural Gas Transportation	70	71	92
NGL Services	64	44	28
Contract Services	—	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 135	$ 105	$ 120
Expenditures for Long-Lived Assets			
Gathering and Processing	$ 721	$ 395	$ 282
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	311	164	120
Corporate	2	1	4
Eliminations	—	—	—
Total	$ 1,034	$ 560	$ 406

	December 31, 2013		
	2013	2012	2011
Assets			
Gathering and Processing	$ 4,748	$ 4,210	$ 1,960
Natural Gas Transportation	991	1,232	1,297
NGL Services	1,070	948	629
Contract Services	1,897	1,672	1,621
Corporate	76	61	61
Eliminations	—	—	—
Total	$ 8,782	$ 8,123	$ 5,568
Investment in Unconsolidated Affiliates			
Gathering and Processing	$ 36	$ 35	$ —
Natural Gas Transportation	991	1,231	1,296
NGL Services	1,070	948	629
Contract Services	—	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 2,097	$ 2,214	$ 1,925
Goodwill			
Gathering and Processing	$ 651	$ 651	$ 313
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	477	477	477
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 1,128	$ 1,128	$ 790

The table below provides a reconciliation of total segment margin to income before income taxes:

	Years Ended December 31,		
	2013	2012	2011
Total segment margin	$ 728	$ 613	$ 421
Operation and maintenance	(296)	(228)	(147)
General and administrative	(88)	(100)	(67)
(Loss) gain on assets sales, net	(2)	(3)	2
Depreciation and amortization	(287)	(252)	(169)
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29 *	17
Income before income taxes	$ 26	$ 34	$ 74

* Other income and deductions, net for the year ended December 31, 2012, included a one-time producer payment of $16 million related to an assignment of certain contracts.

17. Equity-Based Compensation

In December 2011, the Partnership's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase the Partnership's common units; awards of the Partnership's restricted units, phantom units and common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of the Partnership and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by the Compensation Committee of the board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of the Partnership's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by the board of directors or the Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of common units available for awards under the plan; however, any material amendment, such as a change in the types of awards available under the plan, would require the approval of the unitholders of the Partnership. The Compensation Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by the board of directors.

Unit-based compensation expense of $7 million, $5 million, and $3 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2013, 2012 and 2011, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2013, 2012, and 2011 is as follows:

2013

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,550	$ 21.96
Exercised	(14,000)	21.14
Outstanding at end of period	142,550	22.04
Exercisable at the end of the period	142,550	

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 2.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units. In January 2014, the Partnership awarded 668,074 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Distributions on the phantom units will be paid concurrent with the Partnership's distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom unit activity for the years ended December 31, 2013, 2012 and 2011:

2013		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,231,342	$ 23.22
Service condition grants	62,360	25.44
Vested service condition	(231,163)	24.80
Forfeited service condition	(35,900)	23.22
Forfeited market condition	(44,397)	19.52
Total outstanding at end of period	982,242	23.16

2012		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,086,393	$ 24.51
Service condition grants	503,625	21.39
Vested service condition	(223,258)	24.71
Vested market condition	(10,200)	19.52
Forfeited service condition	(120,868)	24.85
Forfeited market condition	(4,350)	19.52
Total outstanding at end of period	1,231,342	23.22

2011		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	742,517	$ 23.61
Service condition grants	596,320	24.55
Vested service condition	(142,520)	24.73
Vested market condition	(8,550)	19.52
Forfeited service condition	(88,474)	24.99
Forfeited market condition	(12,900)	19.52
Total outstanding at end of period	1,086,393	24.51

The Partnership expects to recognize $19 million of unit-based compensation expense related to non-vested phantom units over a period of 3.3 years.

18. Quarterly Financial Data (Unaudited)

	Quarter Ended			
2013	**December 31**	**September 30**	**June 30**	**March 31**
Operating revenues	$ 677	$ 665	$ 639	$ 540
Operating income (loss)	12	24	34	(15)
Net (loss) income attributable to Regency Energy Partners LP	(1)	39	10	(29)
Earnings per common units:				
Basic net (loss) income per common unit	(0.03)	0.16	0.07	(0.06)
Diluted net (loss) income per common unit	(0.03)	0.05	0.07	(0.06)

	Quarter Ended			
2012 *	**December 31**	**September 30**	**June 30**	**March 31**
Operating revenues	$ 587	$ 527	$ 511	$ 375
Operating income (loss)	8	5	22	(5)
Net (loss) income attributable to Regency Energy Partners LP	(8)	(1)	26	15
Earnings per common units:				
Basic net (loss) income per common unit	(0.08)	(0.04)	0.14	0.15
Diluted net (loss) income per common unit	(0.08)	(0.04)	0.10	0.14

* Due to the SUGS Acquisition, these quarterly results have been retrospectively adjusted to include the operations of SUGS beginning March 26, 2012, the date upon which common control began.

5. REGENCY GP LP AND SUBSIDIARIES CONSOLIDATED FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Report of Independent Registered Public Accounting Firm	S - 179
Consolidated Balance Sheets – December 31, 2013 and 2012	S - 180
Consolidated Statements of Operations – Years Ended December 31, 2013, 2012 and 2011	S - 181
Consolidated Statements of Comprehensive Income – Years Ended December 31, 2013, 2012 and 2011	S - 182
Consolidated Statements of Partners' Capital and Noncontrolling Interest – Years Ended December 31, 2013, 2012 and 2011	S - 183
Consolidated Statements of Cash Flows – Years Ended December 31, 2013, 2012 and 2011	S - 184
Notes to Consolidated Financial Statements	S - 185

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency GP LP

We have audited the accompanying consolidated balance sheets of Regency GP LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' capital and noncontrolling interest 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 financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Partnership's investment in which is accounted for under the equity method of accounting. The Partnership's investment in Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 was $548 million and $581 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $39 million, $42 million, and $43 million, respectively, for each of the three years in the period ended December 31, 2013. Those statements were audited by other auditors, whose reports has been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the reports 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. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency GP LP 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.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control, which has been accounted for in a manner similar to a pooling of interests.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Regency GP LP

Consolidated Balance Sheets
(in millions)

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 53
Trade accounts receivable	292	222
Related party receivables	28	8
Inventories	42	27
Other current assets	19	30
Total current assets	400	340
Property, Plant and Equipment:		
Gathering and transmission systems	1,671	1,308
Compression equipment	1,627	1,326
Gas plants and buildings	825	568
Other property, plant and equipment	414	377
Construction-in-progress	513	507
Total property, plant and equipment	5,050	4,086
Less accumulated depreciation	(632)	(400)
Property, plant and equipment, net	4,418	3,686
Other Assets:		
Investments in unconsolidated affiliates	2,097	2,214
Other, net of accumulated amortization of debt issuance costs of $24 and $17	57	43
Total other assets	2,154	2,257
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $107 and $77	682	712
Goodwill	1,128	1,128
Total intangible assets and goodwill	1,810	1,840
TOTAL ASSETS	$ 8,782	$ 8,123
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 26	$ 10
Trade accounts payable	291	255
Related party payables	69	95
Accrued interest	38	30
Other current liabilities	51	99
Total current liabilities	475	489
Long-term derivative liabilities	19	25
Other long-term liabilities	30	39
Long-term debt, net	3,310	2,157
Commitments and contingencies		
Regency's Series A Preferred Units, redemption amount of $38 and $85	32	73
Partners' Capital and Noncontrolling Interest:		
Partners' capital	782	326
Predecessor equity	—	1,733
Total partners' capital	782	2,059
Noncontrolling interest	4,134	3,281
Total partners' capital and noncontrolling interest	4,916	5,340
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 8,782	$ 8,123

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Operations
(in millions)

	Years Ended December 31,		
	2013	2012	2011
REVENUES			
Gas sales, including related party amounts of $71, $42, and $23	$ 826	$ 508	$ 456
NGL sales, including related party amounts of $81, $28, and $365	1,053	991	603
Gathering, transportation and other fees, including related party amounts of $26, $29, and $24	545	401	351
Net realized and unrealized (loss) gain from derivatives	(8)	23	(19)
Other, including related party amounts of $-, $1, and $10	105	77	43
Total revenues	2,521	2,000	1,434
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $56, $35, and $22	1,793	1,387	1,013
Operation and maintenance	296	228	147
General and administrative, including related party amounts of $11, $15, and $17	88	100	67
Loss (gain) on asset sales, net	2	3	(2)
Depreciation and amortization	287	252	169
Total operating costs and expenses	2,466	1,970	1,394
OPERATING INCOME	55	30	40
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29	17
INCOME BEFORE INCOME TAXES	26	34	74
Income tax benefit	(1)	—	—
NET INCOME	$ 27	$ 34	$ 74
Net income attributable to noncontrolling interest	(16)	(25)	(67)
NET INCOME ATTRIBUTABLE TO REGENCY GP LP	$ 11	$ 9	$ 7

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Comprehensive Income
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 27	$ 34	$ 74
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	6	19
Change in fair value of cash flow hedges	—	(4)	(13)
Total other comprehensive income	$ —	$ 2	$ 6
Comprehensive income	$ 27	$ 36	$ 80
Comprehensive income attributable to noncontrolling interest	16	25	67
Comprehensive income attributable to Regency GP LP	$ 11	$ 11	$ 13

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in millions)

	Partners' Interest	AOCI	Predecessor Equity	Noncontrolling Interest	Total
Balance—December 31, 2010	$ 333	$ (11)	$ —	$ 2,972	$ 3,294
Regency common unit offerings, net of costs	—	—	—	436	436
Regency unit-based compensation expenses	—	—	—	3	3
Distributions to partners and noncontrolling interests	(10)	—	—	(264)	(274)
Net income	7	—	—	67	74
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Net cash flow hedge amounts reclassified to earnings	—	19	—	—	19
Net change in fair value of cash flow hedges	—	(13)	—	—	(13)
Balance—December 31, 2011	$ 330	$ (5)	$ —	$ 3,206	$ 3,531
Regency common unit offerings, net of costs	—	—	—	312	312
Regency common units issued under LTIP, net of forfeitures and tax withholding	—	—	—	(1)	(1)
Regency unit-based compensation expenses	—	—	—	5	5
Distributions to partners and noncontrolling interests	(13)	—	—	(309)	(322)
Net income	9	—	(14)	39	34
Contributions from noncontrolling interest	—	—	—	42	42
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Accretion of Series A Preferred Units	—	—	—	(2)	(2)
Net cash flow hedge amounts reclassified to earnings	—	5	—	—	5
Contribution of net investment to unitholders	—	(3)	1,747	—	1,744
Balance—December 31, 2012	$ 326	$ (3)	$ 1,733	$ 3,284	$ 5,340
Contribution of net investment to Regency	1,925	3	(1,928)	—	—
Regency issuance of common units in connection with the SUGS Acquisition, net of costs	(819)	—	—	819	—
Regency issuance of Regency Class F common units in connection with the SUGS Acquisition, net of costs	(142)	—	—	142	—
Contribution of assets between entities under common control below historical cost	(504)	—	231	—	(273)
Regency common unit offerings, net of costs	—	—	—	149	149
Conversion of Regency Series A Preferred Units for common units	—	—	—	41	41
Regency unit-based compensation expenses	—	—	—	7	7
Distributions to partners, noncontrolling interests and subsidiary's unvested unit awards	(15)	—	—	(371)	(386)
Contributions from noncontrolling interest	—	—	—	17	17
Net income	11	—	(36)	52	27
Distributions to Regency Series A Preferred Units	—	—	—	(6)	(6)
Balance—December 31, 2013	$ 782	$ —	$ —	$ 4,134	$ 4,916

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Cash Flows
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net income	$ 27	$ 34	$ 74
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	293	259	175
Income from unconsolidated affiliates	(135)	(105)	(120)
Derivative valuation changes	6	(12)	(21)
Loss (gain) on asset sales, net	2	3	(2)
Regency unit-based compensation expenses	7	5	3
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	(96)	—	(8)
Other current assets and other current liabilities	(54)	10	11
Trade accounts payable, related party payables and deferred revenues	119	18	23
Distributions of earnings received from unconsolidated affiliates	142	121	119
Cash flow changes in other assets and liabilities	125	(9)	—
Net cash flows provided by operating activities	436	324	254
INVESTING ACTIVITIES			
Capital expenditures	(1,034)	(560)	(406)
Capital contributions to unconsolidated affiliates	(148)	(356)	(53)
Distributions in excess of earnings of unconsolidated affiliates	249	83	74
Acquisition of investment in unconsolidated affiliates, net of cash received	—	—	(594)
Acquisitions, net of cash received	(475)	—	—
Proceeds from asset sales	15	26	24
Net cash flows used in investing activities	(1,393)	(807)	(955)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	318	(140)	47
Proceeds from issuance of senior notes	1,000	700	500
Redemptions of senior notes	(163)	(88)	—
Debt issuance costs	(24)	(15)	(10)
Distributions to non-controlling interest and subsidiary distributions on unvested unit awards	(371)	(309)	(264)
Partner distributions	(15)	(13)	(10)
Contributions from noncontrolling interest	17	42	—
Contributions from previous parent	—	51	—
Drafts payable	18	4	2
Subsidiary common units issued under LTIP, net of forfeitures and tax withholding	—	(1)	—
Proceeds from Regency issuance of common units, net of issuance costs	149	312	436
Distributions to Regency Series A Preferred Units	(6)	(8)	(8)
Net cash flows provided by financing activities	923	535	693
Net change in cash and cash equivalents	(34)	52	(8)
Cash and cash equivalents at beginning of period	53	1	9
Cash and cash equivalents at end of period	$ 19	$ 53	$ 1
Supplemental cash flow information:			
Accrued capital expenditures	$ 60	$ 136	$ 24
Issuance of Class F and common units in connection with SUGS Acquisition	961	—	—
Interest paid, net of amounts capitalized	146	112	83
Income taxes paid	—	—	2
Accrued capital contribution to unconsolidated affiliate	13	23	—

See accompanying notes to consolidated financial statements

Regency GP LP
Notes to Consolidated Financial Statements
(Tabular dollar amounts are in millions)

1. Organization and Basis of Presentation

Organization of Regency GP LP. Regency GP LP (the "General Partner") is the general partner of Regency Energy Partners LP. The General Partner owns a 1.3% general partner interest and the incentive distribution rights of Regency Energy Partners LP. Regency GP LLC owns a 0.001% general partner interest in the General Partner and the remaining limited partner interest is owned by ETE GP Acquirer LLC, which is a wholly-owned subsidiary of Energy Transfer Equity, L.P. ("ETE").

Organization of Regency Energy Partners LP. Regency Energy Partners LP and its subsidiaries ("Regency" or the "Partnership") are engaged in the business of gathering, processing and transporting natural gas and natural gas liquids ("NGLs") as well as providing contract compression services.

SUGS Acquisition. In April 2013, the Partnership acquired Southern Union Gas Services ("SUGS") from Southern Union Company ("Southern Union"), a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 of Regency common units and 6,274,483 Regency Class F common units. The Regency Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The Regency common units and Regency Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Regency Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the net proceeds of $600 million of senior notes issued by the Partnership on April 30, 2013 in a private placement. In December 2013, these senior notes were exchanged for senior notes that are substantially identical, except that the exchange senior notes are registered under federal securities law and do not have any transfer restrictions. In January 2014, Panhandle Eastern Pipe Line Company, LP ("PEPL") entered into an agreement and plan of merger with Southern Union and PEPL Holdings, LLC ("PEPL Holdings"), pursuant to which each of Southern Union and PEPL Holdings were merged with and into PEPL, with PEPL as the surviving entity. In connection with this merger, PEPL assumed the guarantee of collection with respect to the payment of the principal amounts of the senior notes issued.

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began).

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

	April 30, 2013
Current assets	$ 113
Property, plant and equipment, net	1,608
Goodwill	337
Other non-current assets	1
Total assets acquired	$ 2,059
Less:	
Current liabilities	(93)
Non-current liabilities	(36)
Net assets acquired	$ 1,930

The following table presents the revenues and net income for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS [1]	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS [1]	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

Basis of presentation. The consolidated financial statements of the General Partner have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation. Subsequent events have been evaluated through February 27, 2014, the date the financial statements were issued.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending on the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

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

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of Energy Transfer Partners ("ETP"). As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with 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.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending on the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

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

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of Energy Transfer Partners ("ETP"). As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with 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.

Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with 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.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The

Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

4. Acquisitions and Dispositions

2013

SUGS Acquisition. The SUGS Acquisition is discussed in footnote 1 - Organization and Basis of Presentation.

PVR Acquisition. In October 2013, the Partnership announced that it entered into a merger agreement with PVR Partners, L.P. ("PVR") pursuant to which the Partnership intends to merge with PVR ("PVR Acquisition"). This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. In November 2013, the Partnership received approval of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in March 2014.

The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock Energy Partners, L.P.'s ("Eagle Rock's") midstream business for approximately $1.3 billion (the "Eagle Rock Midstream Acquisition"). This acquisition is expected to complement the Partnership's core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Hoover Energy Acquisition. On February 3, 2014, the Partnership completed its previously announced acquisition of the subsidiaries of Hoover Energy Partners, LP that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in West Texas. The consideration paid by the Partnership was valued at $281.6 million (subject to customary post-closing adjustments) and consisted of (i) 4,040,471 Regency common units issued to Hoover and (ii) $183.6 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership will account for the acquisition of Hoover 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. Management's evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements.

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star NGL LLC ("Lone Star"), in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 Regency common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

Ranch JV. On December 2, 2011, Ranch Westex JV LLC ("Ranch JV") was formed by the Partnership, Anadarko Pecos Midstream LLC and Chesapeake West Texas Processing, L.L.C., each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in West Texas.

5. Investments in Unconsolidated Affiliates

As of December 31, 2013, the Partnership has a 49.99% general partner interest in RIGS Haynesville Partnership Co. ("HPC"), a 50% membership interest in Midcontinent Express Pipeline LLC ("MEP"), a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% membership interest in Grey Ranch. The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011, a 49.9% interest in MEP in May 2010 and a 0.1% interest in MEP in September 2011. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2013 and 2012 is as follows:

	December 31, 2013	December 31, 2012
HPC	$ 442	$ 650
MEP	548	581
Lone Star	1,070	948
Ranch JV	36	35
Grey Ranch	1	—
	$ 2,097	$ 2,214

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013				
	HPC [2]	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 137	$ 2	$ —
Distributions	238	72	79	2	—
Share of net income	36	39	64	1	1
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 343	$ 36	$ —
Distributions	61	75	68	—	—
Share of net income	35	42	44	(1)	(9)
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2011				
	HPC	MEP[3]	Lone Star[4]	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 645	$ —	N/A
Purchase of additional interest	—	1	—	—	N/A
Distributions	65	83	22	—	N/A
Return of investment	—	—	23	—	N/A
Share of net income	55	43	28	—	N/A
Amortization of excess fair value of investment [1]	(6)	—	—	—	N/A

(1) The Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $445 million as of December 31, 2013. The Partnership's contingent obligation with respect to the outstanding borrowings under this facility was $222 million at December 31, 2013.

(3) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(4) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 50% interest in Grey Ranch in March 2012, as part of the SUGS Acquisition in April 2013.

6. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (natural gas liquids, including propane, normal butane, iso butane and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2013, the Partnership had an immaterial amount in net hedging gains in AOCI, all of which will be amortized to earnings over the next three months.

As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps with a total notional amount of 4,562,500 MMBtu for 2012. These natural gas price swaps were accounted for as cash flow hedges, with effective portion of changes in their fair value recorded to AOCI and reclassified into revenues in the same period which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2013, the Partnership had $510 million of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership's resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party.

If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2013 was $4 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Regency Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2013 and 2012 are detailed below:

	Assets		Liabilities	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ —	$ —	$ —	$ 5
Total cash flow hedging instruments	—	—	—	5
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 3	$ 4	$ 9	$ 1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	19	25
Total derivatives	$ 4	$ 5	$ 28	$ 31

The Partnership's statements of operations for the years ended December 31, 2013, 2012 and 2011 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)		
Commodity derivatives		$ —	$ (4)	$ (13)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
Commodity derivatives	Revenue	$ —	$ 6	$ (19)

		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income		
Commodity derivatives	Revenue	$ —	$ (5)	$ —
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Recognized in Income on Derivatives		
Commodity derivatives	Revenue	$ (9)	$ 16	$ —
Embedded derivatives	Other income & deductions	6	14	18
		$ (3)	$ 30	$ 18

7. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31, 2013	December 31, 2012
Senior notes	$ 2,800	$ 1,965
Revolving loans	510	192
Total	3,310	2,157
Less: current portion	—	—
Long-term debt	$ 3,310	$ 2,157
Availability under revolving credit facility:		
Total credit facility limit	$ 1,200	$ 1,150
Revolving loans	(510)	(192)
Letters of credit	(14)	(12)
Total available	$ 676	$ 946

Long-term debt maturities as of December 31, 2013 for each of the next five years are as follows:

Year Ended December 31,	Amount
2014	$ —
2015	—
2016	—
2017	—
2018	600
Thereafter	2,710
Total	$ 3,310

Revolving Credit Facility

In the year ended December 31, 2013, 2012 and 2011 the Partnership borrowed $1.46 billion, $1.56 billion and $940 million, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the same periods, the Partnership repaid $1.1 billion, $1.70 billion and $893 million, respectively, with proceeds from equity offerings and issuances of senior notes.

In May 2013, Regency Gas Services, LP, a wholly-owned subsidiary of Regency Energy Partners LP, entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a “Restricted Subsidiary” structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

The Partnership capitalized $6 million of net loan fees which is being amortized over the remaining term.

The revolving credit facility and the guarantees are senior to the Partnership’s and the guarantors’ unsecured obligations, to the extent of the value of the assets securing such obligations.

As of December 31, 2013, the Partnership was in compliance in all material respects with all of the financial covenants contained within the new credit agreement.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.625% to 1.50% for base rate loans, 1.625% to 2.50% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.17% and 2.93% as of December 31, 2013 and 2012, respectively.

RGS must pay (i) a commitment fee ranging from 0.30% to 0.45% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.625% to 2.50% per annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.00 for the first eight quarters (after March 2015, an increase is allowed in the permitted total leverage ratio for the first two fiscal quarters following any $50 million or greater acquisition), consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2013 and 2012, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extension thereof.

In February 2014, RGS entered into the first Amendment to the Sixth Amended and restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the credit agreement.

Senior Notes

In May 2009, the Partnership and Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership, issued $250 million of senior notes that mature on June 1, 2016 (the "2016 Notes"). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $88 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

The Partnership and Finance Corp. have outstanding the following series of senior notes (collectively "Senior Notes"):

- $600 million in aggregate principal amount of our 6 ⅞% senior notes due December 1, 2018 (the "2018 Notes") with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 5 ¾% senior notes due September 1, 2020 (the "2020 Notes") with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6 ½% senior notes due July 15, 2021 (the "2021 Notes") with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5 ⅞% senior notes due March 1, 2022 (the "2022 Notes") issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5 ½% senior notes due April 15, 2023 (the "2023 5 ½% Notes") with interest payable semi-annually in arrears on April 15 and October 15; and
- $600 million in aggregate principal amount of our 4 ½% senior notes due November 1, 2023 (the "2023 4 ½% Notes") with interest payable semi-annually in arrears on May 1 and November 1.

The Senior Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date.

- 2018 Notes - Beginning December 1, 2014 100% may be redeemed at fixed redemption price of 103.438% (December 1, 2015 - 101.719% and December 1, 2016 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5 ½% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4 ½% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each note holder of the Senior Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. The Partnership's ability to purchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The existing senior notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody's and Standard & Poor's and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2013, we were in compliance with these covenants.

8. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2012	$ 681	$ 60	$ 741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	655	57	712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	$ 629	$ 53	$ 682

The average remaining amortization periods for customer relations and trade names are 24 and 16 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $30 million.

9. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Regency Series A Preferred Units. Derivatives related to commodity swaps are valued using observable inputs for similar instruments and incorporate Level 1 and Level 2 inputs. Embedded derivatives related to the Regency Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31, 2013			Fair Value Measurement at December 31, 2012		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 2	$ 2	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	2	2	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Natural Gas Liquids	4	4	—	1	1	—
Condensate	1	1	—	—	—	—
Embedded Derivatives in Regency Series A Preferred Units	19	—	19	25	—	25
Total Liabilities	$ 28	$ 9	$ 19	$ 31	$ 6	$ 25

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Regency Series A Preferred Units:

Unobservable Input	December 31, 2013
Credit Spread	4.16%
Volatility	23.71%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2013 and 2012. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2013 and 2012.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2012	$ 39
Change in fair value	(14)
Balance at December 31, 2012	25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	$ 19

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2013 was $2.83 billion and $2.80 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.97 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

10. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2013:

For the year ending December 31,	Operating Lease
2014	$ 3
2015	3
2016	2
2017	2
2018	2
Thereafter	34
Total minimum lease payments	$ 46

Total rent expense for operating leases, including those leases with terms of less than one year, was $11 million, $11 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

11. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

The table below reflects the environmental liabilities recorded in the consolidated balance sheet at December 31, 2013 and 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31, 2013	December 31, 2012
Current	$ 2	$ 5
Noncurrent	6	7
Total environmental liabilities	$ 8	$ 12

The Partnership made expenditures related to environmental remediation of $5 million for the year ended December 31, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

CDM Sales Tax Audit. CDM Resource Management LLC ("CDM"), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, the Partnership is unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, none of which are believed to be potentially material to the Partnership at this time.

12. Regency Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Regency Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner's contribution of $2 million. The Regency Series A Preferred Units are convertible to Regency common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value") and accrued interest. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010.

Holders may elect to convert Regency Series A Preferred Units to common units at any time. In July 2013, certain holders of Regency Series A Preferred Units exercised their right to convert 2,459,017 Regency Series A Preferred Units into Regency common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Regency Series A Preferred Units into Regency common units. As of December 31, 2013, the remaining Regency Series A Preferred Units were convertible into 2,050,854 Regency common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership's common unit distributions.

Distributions on the Regency Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of Regency common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Regency Series A Preferred Units, (2) reduces the distributions on the Regency common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions,

such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Regency Series A Preferred Units, all future distributions on the Regency Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Regency Series A Preferred Unit per quarter, (2) $0.09125 per Regency Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Regency Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Regency Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Regency Series A Preferred Units are convertible, at the holder's option, into Regency common units, provided that the holder must request conversion of at least 375,000 Regency Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of Regency common units issuable is equal to the issue price of the Regency Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Regency Series A Preferred Units into Regency common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Regency Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Regency Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2013, the Series A Preferred Units were convertible to 2,050,854 common units.

The following table provides a reconciliation of the beginning and ending balances of the Regency Series A Preferred Units for the year ended December 31, 2013 and 2012:

	Units	Amount	
Balance at January 1, 2012	4,371,586	$ 71	
Accretion to redemption value	N/A	2	
Balance at December 31, 2012	4,371,586	73	
Regency Series A Preferred Units converted into common units	(2,459,017)	(41)	
Balance at December 31, 2013	1,912,569	$ 32	*

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from

partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

13. Related Party Transactions

As of December 31, 2013 and 2012, details of the Partnership's related party receivables and related party payables were as follows:

	December 31, 2013	December 31, 2012
Related party receivables		
HPC	$ 1	$ 1
ETE and its subsidiaries	25	5
Ranch JV	2	2
Total related party receivables	$ 28	$ 8
Related party payables		
HPC	$ 1	$ 1
ETE and its subsidiaries	68	94
Total related party payables	$ 69	$ 95

Transactions with ETE and its subsidiaries. Under the service agreement with ETE Services Company, LLC ("Services Co."), the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, Energy Transfer Company ("ETC"), the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties. The Operation and Service Agreement Amendment describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $11 million for the year ended December 31, 2013, and $17 million for the years ended December 31, 2012 and 2011.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $63 million, $62 million and $57 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2013 and 2012, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

The Partnership's gathering and processing operations, in the ordinary course of business, sells natural gas and NGL to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's contract services operations provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's contract services operations did not sell compression equipment to a subsidiary of ETP for the year ended December 31, 2013, and sold $1 million for the year ended December 31, 2012. As these transactions are between entities under common control, partners' capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's contract services operations purchased compression equipment from a subsidiary of ETP for $95 million and $29 million during the years ended December 31, 2013 and 2012, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided

by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2013, 2012, and 2011, the related party general and administrative expenses reimbursed to the Partnership were $18 million, $20 million, and $17 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's contract services operations provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with Lone Star. In 2013, the Partnership entered into a nineteen month agreement to sell NGL to Lone Star for approximately $5 million per month. For the year ended December 31, 2013, the Partnership had recorded $26 million in NGL sales under this contract.

Transactions with Enterprise Product Partners L.P. and its subsidiaries. In January 2012, Enterprise Products Partners L.P. ("EPD") sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

14. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of Regency's reporting segment.

	Regency Reportable Segment	Years Ended December 31, 2013	2012	2011
Customer				
Customer A	Gathering and Processing	$ 381	$ 367	$ 366
Customer B	Gathering and Processing	362	451	—
Supplier				
Supplier A	Gathering and Processing	164	171	133
Supplier B	Gathering and Processing	185	—	—

Regency is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

15. Regency's Equity-Based Compensation

In December 2011, Regency's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase Regency's common units; awards of Regency's restricted units, Regency phantom units and Regency common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of Regency and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by Regency's Compensation Committee of its board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of Regency's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by Regency's board of directors or its Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of Regency common units available for awards under the plan; however, any material amendment, such as a change in the types of Regency awards available under the plan, would require the Regency's unitholder approval. Regency's Compensation Committee is also authorized to make

adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by Regency's board of directors.

Unit-based compensation expense of $7 million, $5 million, and $3 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2013, 2012 and 2011, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2013, 2012, and 2011 is as follows:

2013

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,550	$ 21.96
Exercised	(14,000)	21.14
Outstanding at end of period	142,550	22.04
Exercisable at the end of the period	142,550	

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 2.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units. In January 2014, the Partnership awarded 668,074 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Distributions on the phantom units will be paid concurrent with the Partnership's distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom unit activity for the years ended December 31, 2013, 2012 and 2011:

2013		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,231,342	$ 23.22
Service condition grants	62,360	25.44
Vested service condition	(231,163)	24.80
Forfeited service condition	(35,900)	23.22
Forfeited market condition	(44,397)	19.52
Total outstanding at end of period	982,242	23.16

2012		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,086,393	$ 24.51
Service condition grants	503,625	21.39
Vested service condition	(223,258)	24.71
Vested market condition	(10,200)	19.52
Forfeited service condition	(120,868)	24.85
Forfeited market condition	(4,350)	19.52
Total outstanding at end of period	1,231,342	23.22

2011		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	742,517	$ 23.61
Service condition grants	596,320	24.55
Vested service condition	(142,520)	24.73
Vested market condition	(8,550)	19.52
Forfeited service condition	(88,474)	24.99
Forfeited market condition	(12,900)	19.52
Total outstanding at end of period	1,086,393	24.51

The Partnership expects to recognize $19 million of unit-based compensation expense related to non-vested phantom units over a period of 3.3 years.

6. ETE GP ACQUIRER LLC AND SUBSIDIARIES CONSOLIDATED FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Report of Independent Registered Public Accounting Firm	S - 209
Consolidated Balance Sheets – December 31, 2013 and 2012	S - 210
Consolidated Statements of Operations – Years Ended December 31, 2013, 2012 and 2011	S - 211
Consolidated Statements of Comprehensive Income – Years Ended December 31, 2013, 2012 and 2011	S - 212
Consolidated Statements of Member's Equity and Noncontrolling Interest – Years Ended December 31, 2013, 2012 and 2011	S - 213
Consolidated Statements of Cash Flows – Years Ended December 31, 2013, 2012 and 2011	S - 214
Notes to Consolidated Financial Statements	S - 215

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Member
ETE GP Acquirer LLC

We have audited the accompanying consolidated balance sheets of ETE GP Acquirer LLC (a Delaware limited liability company) and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and member's equity and noncontrolling interest for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Company's investment in which is accounted for under the equity method of accounting. The Company's investment in Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 was $548 million and $581 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $39 million, $42 million, and $43 million, respectively, for each of the three years in the period ended December 31, 2013. Those statements were audited by other auditors, whose reports has been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the reports 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of ETE GP Acquirer LLC 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.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control, which has been accounted for in a manner similar to a pooling of interests.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

ETE GP Acquirer LLC

Consolidated Balance Sheets
(in millions)

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 53
Trade accounts receivable	292	222
Related party receivables	28	8
Inventories	42	27
Other current assets	19	30
Total current assets	400	340
Property, Plant and Equipment:		
Gathering and transmission systems	1,671	1,308
Compression equipment	1,627	1,326
Gas plants and buildings	825	568
Other property, plant and equipment	414	377
Construction-in-progress	513	507
Total property, plant and equipment	5,050	4,086
Less accumulated depreciation	(632)	(400)
Property, plant and equipment, net	4,418	3,686
Other Assets:		
Investments in unconsolidated affiliates	2,097	2,214
Other, net of accumulated amortization of debt issuance costs of $24 and $17	57	43
Total other assets	2,154	2,257
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $107 and $77	682	712
Goodwill	1,128	1,128
Total intangible assets and goodwill	1,810	1,840
TOTAL ASSETS	$ 8,782	$ 8,123
LIABILITIES & MEMBER'S EQUITY AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 26	$ 10
Trade accounts payable	291	255
Related party payables	69	95
Accrued interest	38	30
Other current liabilities	51	99
Total current liabilities	475	489
Long-term derivative liabilities	19	25
Other long-term liabilities	30	39
Long-term debt, net	3,310	2,157
Commitments and contingencies		
Regency's Series A Preferred Units, redemption amount of $38 and $85	32	73
Member's Equity and Noncontrolling Interest:		
Member's equity	782	326
Predecessor equity	—	1,733
Total member's equity	782	2,059
Noncontrolling interest	4,134	3,281
Total member's equity and noncontrolling interest	4,916	5,340
TOTAL LIABILITIES AND MEMBER'S EQUITY AND NONCONTROLLING INTEREST	$ 8,782	$ 8,123

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Operations
(in millions)

	Years Ended December 31,		
	2013	2012	2011
REVENUES			
Gas sales, including related party amounts of $71, $42, and $23	$ 826	$ 508	$ 456
NGL sales, including related party amounts of $81, $28, and $365	1,053	991	603
Gathering, transportation and other fees, including related party amounts of $26, $29, and $24	545	401	351
Net realized and unrealized (loss) gain from derivatives	(8)	23	(19)
Other, including related party amounts of $-, $1, and $10	105	77	43
Total revenues	2,521	2,000	1,434
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $56, $35, and $22	1,793	1,387	1,013
Operation and maintenance	296	228	147
General and administrative, including related party amounts of $11, $15, and $17	88	100	67
Loss (gain) on asset sales, net	2	3	(2)
Depreciation and amortization	287	252	169
Total operating costs and expenses	2,466	1,970	1,394
OPERATING INCOME	55	30	40
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29	17
INCOME BEFORE INCOME TAXES	26	34	74
Income tax benefit	(1)	—	—
NET INCOME	$ 27	$ 34	$ 74
Net income attributable to noncontrolling interest	(16)	(25)	(67)
NET INCOME ATTRIBUTABLE TO ETE GP ACQUIRER LLC	$ 11	$ 9	$ 7

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Comprehensive Income
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 27	$ 34	$ 74
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	6	19
Change in fair value of cash flow hedges	—	(4)	(13)
Total other comprehensive income	$ —	$ 2	$ 6
Comprehensive income	$ 27	$ 36	$ 80
Comprehensive income attributable to noncontrolling interest	16	25	67
Comprehensive income attributable to ETE GP Acquirer LLC	$ 11	$ 11	$ 13

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Member's Equity and Noncontrolling Interest
(in millions)

	Member's Equity	AOCI	Predecessor Equity	Noncontrolling Interest	Total
Balance—December 31, 2010	$ 333	$ (11)	$ —	$ 2,972	$ 3,294
Regency common unit offerings, net of costs	—	—	—	436	436
Regency unit-based compensation expenses	—	—	—	3	3
Distributions to partners and noncontrolling interests	(10)	—	—	(264)	(274)
Net income	7	—	—	67	74
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Net cash flow hedge amounts reclassified to earnings	—	19	—	—	19
Net change in fair value of cash flow hedges	—	(13)	—	—	(13)
Balance—December 31, 2011	$ 330	$ (5)	$ —	$ 3,206	$ 3,531
Regency common unit offerings, net of costs	—	—	—	312	312
Regency common units issued under LTIP, net of forfeitures and tax withholding	—	—	—	(1)	(1)
Regency unit-based compensation expenses	—	—	—	5	5
Distributions to partners and noncontrolling interests	(13)	—	—	(309)	(322)
Net income	9	—	(14)	39	34
Contributions from noncontrolling interest	—	—	—	42	42
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Accretion of Series A Preferred Units	—	—	—	(2)	(2)
Net cash flow hedge amounts reclassified to earnings	—	5	—	—	5
Contribution of net investment to unitholders	—	(3)	1,747	—	1,744
Balance—December 31, 2012	$ 326	$ (3)	$ 1,733	$ 3,284	$ 5,340
Contribution of net investment to Regency	1,925	3	(1,928)	—	—
Regency issuance of common units in connection with the SUGS Acquisition, net of costs	(819)	—	—	819	—
Regency issuance of Regency Class F common units in connection with the SUGS Acquisition, net of costs	(142)	—	—	142	—
Contribution of assets between entities under common control below historical cost	(504)	—	231	—	(273)
Regency common unit offerings, net of costs	—	—	—	149	149
Conversion of Regency Series A Preferred Units for common units	—	—	—	41	41
Regency unit-based compensation expenses	—	—	—	7	7
Distributions to partners, noncontrolling interests and subsidiary's unvested unit awards	(15)	—	—	(371)	(386)
Contributions from noncontrolling interest	—	—	—	17	17
Net income	11	—	(36)	52	27
Distributions to Regency Series A Preferred Units	—	—	—	(6)	(6)
Balance—December 31, 2013	$ 782	$ —	$ —	$ 4,134	$ 4,916

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Cash Flows
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net income	$ 27	$ 34	$ 74
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	293	259	175
Income from unconsolidated affiliates	(135)	(105)	(120)
Derivative valuation changes	6	(12)	(21)
Loss (gain) on asset sales, net	2	3	(2)
Regency unit-based compensation expenses	7	5	3
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	(96)	—	(8)
Other current assets and other current liabilities	(54)	10	11
Trade accounts payable, related party payables and deferred revenues	119	18	23
Distributions of earnings received from unconsolidated affiliates	142	121	119
Cash flow changes in other assets and liabilities	125	(9)	—
Net cash flows provided by operating activities	436	324	254
INVESTING ACTIVITIES			
Capital expenditures	(1,034)	(560)	(406)
Capital contributions to unconsolidated affiliates	(148)	(356)	(53)
Distributions in excess of earnings of unconsolidated affiliates	249	83	74
Acquisition of investment in unconsolidated affiliates, net of cash received	—	—	(594)
Acquisitions, net of cash received	(475)	—	—
Proceeds from asset sales	15	26	24
Net cash flows used in investing activities	(1,393)	(807)	(955)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	318	(140)	47
Proceeds from issuance of senior notes	1,000	700	500
Redemptions of senior notes	(163)	(88)	—
Debt issuance costs	(24)	(15)	(10)
Distributions to non-controlling interest and subsidiary distributions on unvested unit awards	(371)	(309)	(264)
Partner distributions	(15)	(13)	(10)
Contributions from noncontrolling interest	17	42	—
Contributions from previous parent	—	51	—
Drafts payable	18	4	2
Subsidiary common units issued under LTIP, net of forfeitures and tax withholding	—	(1)	—
Proceeds from Regency issuance of common units, net of issuance costs	149	312	436
Distributions to Regency Series A Preferred Units	(6)	(8)	(8)
Net cash flows provided by financing activities	923	535	693
Net change in cash and cash equivalents	(34)	52	(8)
Cash and cash equivalents at beginning of period	53	1	9
Cash and cash equivalents at end of period	$ 19	$ 53	$ 1
Supplemental cash flow information:			
Accrued capital expenditures	$ 60	$ 136	$ 24
Issuance of Class F and common units in connection with SUGS Acquisition	961	—	—
Interest paid, net of amounts capitalized	146	112	83
Income taxes paid	—	—	2
Accrued capital contribution to unconsolidated affiliate	13	23	—

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC
Notes to Consolidated Financial Statements
(Tabular dollar amounts are in millions)

1. Organization and Basis of Presentation

Organization of ETE GP Acquirer LLC. ETE GP Acquirer LLC ("GP Acquirer") is a wholly-owned subsidiary of Energy Transfer Equity, L.P. ("ETE") and owns 99.999% of the limited partner interest in Regency GP LP and 100% membership interest in Regency GP LLC, an entity that owns the 0.001% general partner interest in Regency GP LP.

Organization of Regency GP LP. Regency GP LP (the "General Partner") is the general partner of Regency Energy Partners LP. The General Partner owns a 1.3% general partner interest and the incentive distribution rights of Regency Energy Partners LP.

Organization of Regency Energy Partners LP. Regency Energy Partners LP and its subsidiaries ("Regency" or the "Partnership") are engaged in the business of gathering, processing and transporting natural gas and natural gas liquids ("NGLs") as well as providing contract compression services.

SUGS Acquisition. In April 2013, the Partnership acquired Southern Union Gas Services ("SUGS") from Southern Union Company ("Southern Union"), a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 of Regency common units and 6,274,483 Regency Class F common units. The Regency Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The Regency common units and Regency Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Regency Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the net proceeds of $600 million of senior notes issued by the Partnership on April 30, 2013 in a private placement. In December 2013, these senior notes were exchanged for senior notes that are substantially identical, except that the exchange senior notes are registered under federal securities law and do not have any transfer restrictions. In January 2014, Panhandle Eastern Pipe Line Company, LP ("PEPL") entered into an agreement and plan of merger with Southern Union and PEPL Holdings, LLC ("PEPL Holdings"), pursuant to which each of Southern Union and PEPL Holdings were merged with and into PEPL, with PEPL as the surviving entity. In connection with this merger, PEPL assumed the guarantee of collection with respect to the payment of the principal amounts of the senior notes issued.

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began).

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

	April 30, 2013
Current assets	$ 113
Property, plant and equipment, net	1,608
Goodwill	337
Other non-current assets	1
Total assets acquired	$ 2,059
Less:	
Current liabilities	(93)
Non-current liabilities	(36)
Net assets acquired	$ 1,930

The following table presents the revenues and net income for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS [1]	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS [1]	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

Basis of presentation. The consolidated financial statements of the GP Acquirer have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation. Subsequent events have been evaluated through February 27, 2014, the date the financial statements were issued.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending upon the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

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

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of Energy Transfer Partners ("ETP"). As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with 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.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

3. Regency Unit Activity Reflected in Noncontrolling Interest

Regency Units Activity. The changes in Regency's common and Class F units were as follows:

	Regency Common Units	Regency Class F Units
Balance - December 31, 2010	137,281,336	—
Regency common unit offerings, net of costs	20,000,001	—
Regency's issuance of common units under LTIP, net of forfeitures and tax withholding	156,271	—
Balance - December 31, 2011	157,437,608	—
Regency common unit offerings, net of costs	12,650,000	—
Regency's issuance of common units under an equity distribution agreement, net of costs	691,129	—
Regency's issuance of common units under LTIP, net of forfeitures and tax withholding	172,720	—
Balance - December 31, 2012	170,951,457	—
Regency's issuance of common units under LTIP, net of forfeitures and tax withholding	184,995	—
Regency's issuance of common units under an equity distribution agreement, net of costs	5,712,138	—
Conversion of Regency Series A preferred units for Regency common units	2,629,223	—
Regency's Issuance of common units and Class F common units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - December 31, 2013	210,850,232	6,274,483

(1) ETE has agreed to forgo IDR payments on the Regency common units issued with the SUGS Acquisition for twenty-four months post-transaction closing.
(2) Regency's Class F common units are not entitled to participate in Regency's distributions or earnings for twenty-four months post-transaction closing.

Equity Distribution Agreement. In June 2012, Regency entered into an Equity Distribution Agreement with Citi under which Regency may offer and sell its common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for Regency. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by Regency and Citi. Regency may also sell its common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of Regency common units to Citi as principal would be pursuant to the terms of a separate agreement between Regency and Citi. Regency intends to use the net proceeds from the sale of these units for general partnership purposes. For the years ended December 31, 2013 and 2012, Regency received net proceeds of $149 million and $15 million, respectively, from Regency units issued pursuant to this Equity Distribution Agreement. As of December 31, 2013, $34 million remains available to be issued under this agreement.

Public Common Unit Offerings. In March 2012, Regency issued 12,650,000 of its common units representing limited partner interests in a public offering at a price of $24.47 per Regency common unit, resulting in net proceeds of $297 million. In May 2012, Regency used the net proceeds from this offering to redeem 35%, or $88 million, in aggregate principal amounts of its

outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under its revolving credit facility. In August 2010, Regency sold 17,537,500 of its common units and received $408 million in proceeds, inclusive of the General Partner's proportionate capital contribution. In October 2011, Regency issued 11,500,000 of its common units representing limited partnership interests in a public offering at a price of $20.92 per Regency common unit, resulting in net proceeds of $232 million which were used to repay outstanding borrowings under its revolving credit facility.

Private Common Unit Offerings. In May 2011, Regency sold 8,500,001 of its common units representing limited partnership interests resulting in net proceeds of $204 million, to partially fund its capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

Beneficial Conversion Feature. Regency issued 6,274,483 Regency Class F common units in connection with the SUGS Acquisition. At the commitment date (February 27, 2013), the sales price of $23.91 per unit represented a $2.19 per unit discount from the fair value of the Regency's common units as of April 30, 2013. The Class F common units are convertible to common units on a one-for-one basis on May 8, 2015.

Noncontrolling Interest. Regency operates Edwards Lime Gathering LLC and its operating subsidiaries (" ELG"), a gas gathering joint venture in South Texas in which other third party companies own a 40% interest, which is reflected on Regency's consolidated balance sheet as noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights . The General Partner is entitled to its proportionate share of all quarterly distributions that Regency makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2% interest in these distributions has been reduced since the Partnership has issued additional units and the General Partner has not contributed a proportionate amount of capital to the Partnership to maintain its General Partner interest. The General Partner ownership interest as of December 31, 2013 was 1.3%. This General Partner interest is represented by 2,834,381 equivalent units as of December 31, 2013.

The IDRs held by the General Partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's IDRs are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its general partner interest.

In connection with the SUGS Acquisition, ETE agreed to forgo IDR payments on Regency common units issued with this transaction for the twenty-four months post-transaction closing.

Distributions. Regency made the following cash distributions per unit during the years ended December 31, 2013 and 2012:

Distribution Date	Cash Distribution (per common unit)
November 14, 2013	$ 0.470
August 14, 2013	0.465
May 13, 2013	0.460
February 14, 2013	0.460
November 14, 2012	$ 0.460
August 14, 2012	0.460
May 14, 2012	0.460
February 13, 2012	0.460

Regency paid a cash distribution of $0.475 per common unit on February 14, 2014.

4. Acquisitions and Dispositions

2013

SUGS Acquisition. The SUGS Acquisition is discussed in footnote 1 - Organization and Basis of Presentation.

PVR Acquisition. In October 2013, the Partnership announced that it entered into a merger agreement with PVR Partners, L.P. ("PVR") pursuant to which the Partnership intends to merge with PVR ("PVR Acquisition"). This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. In November 2013, the Partnership received approval of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in March 2014.

The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock Energy Partners, L.P.'s ("Eagle Rock's") midstream business for approximately $1.3 billion (the "Eagle Rock Midstream Acquisition"). This acquisition is expected to complement the Partnership's core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Hoover Energy Acquisition. On February 3, 2014, the Partnership completed its previously announced acquisition of the subsidiaries of Hoover Energy Partners, LP that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in West Texas. The consideration paid by the Partnership was valued at $281.6 million (subject to customary post-closing adjustments) and consisted of (i) 4,040,471 Regency common units issued to Hoover and (ii) $183.6 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership will account for the acquisition of Hoover 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. Management's evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements.

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star NGL LLC ("Lone Star"), in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 Regency common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

Ranch JV. On December 2, 2011, Ranch Westex JV LLC ("Ranch JV") was formed by the Partnership, Anadarko Pecos Midstream LLC and Chesapeake West Texas Processing, L.L.C., each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in West Texas.

5. Investments in Unconsolidated Affiliates

As of December 31, 2013, the Partnership has a 49.99% general partner interest in RIGS Haynesville Partnership Co. ("HPC"), a 50% membership interest in Midcontinent Express Pipeline LLC ("MEP"), a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% membership interest in Grey Ranch. The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011, a 49.9% interest in MEP in May 2010 and a 0.1% interest in MEP in September 2011. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2013 and 2012 is as follows:

	December 31, 2013	December 31, 2012
HPC	$ 442	$ 650
MEP	548	581
Lone Star	1,070	948
Ranch JV	36	35
Grey Ranch	1	—
	$ 2,097	$ 2,214

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013				
	HPC [2]	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 137	$ 2	$ —
Distributions	238	72	79	2	—
Share of net income	36	39	64	1	1
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 343	$ 36	$ —
Distributions	61	75	68	—	—
Share of net income	35	42	44	(1)	(9)
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2011				
	HPC	MEP[3]	Lone Star[4]	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 645	$ —	N/A
Purchase of additional interest	—	1	—	—	N/A
Distributions	65	83	22	—	N/A
Return of investment	—	—	23	—	N/A
Share of net income	55	43	28	—	N/A
Amortization of excess fair value of investment [1]	(6)	—	—	—	N/A

(1) The Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $445 million as of December 31, 2013. The Partnership's contingent obligation with respect to the outstanding borrowings under this facility was $222 million at December 31, 2013.

(3) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(4) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 50% interest in Grey Ranch in March 2012, as part of the SUGS Acquisition in April 2013.

6. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (natural gas liquids, including propane, normal butane, iso butane and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2013, the Partnership had an immaterial amount in net hedging gains in AOCI, all of which will be amortized to earnings over the next three months.

As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps with a total notional amount of 4,562,500 MMBtu for 2012. These natural gas price swaps were accounted for as cash flow hedges, with effective portion of changes in their fair value recorded to AOCI and reclassified into revenues in the same period which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2013, the Partnership had $510 million of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership's resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2013 was $4 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Regency Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2013 and 2012 are detailed below:

	Assets		Liabilities	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ —	$ —	$ —	$ 5
Total cash flow hedging instruments	—	—	—	5
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 3	$ 4	$ 9	$ 1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	19	25
Total derivatives	$ 4	$ 5	$ 28	$ 31

The Partnership's statements of operations for the years ended December 31, 2013, 2012 and 2011 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)		
Commodity derivatives		$ —	$ (4)	$ (13)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
Commodity derivatives	Revenue	$ —	$ 6	$ (19)

		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income		
Commodity derivatives	Revenue	$ —	$ (5)	$ —
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Recognized in Income on Derivatives		
Commodity derivatives	Revenue	$ (9)	$ 16	$ —
Embedded derivatives	Other income & deductions	6	14	18
		$ (3)	$ 30	$ 18

7. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31, 2013	December 31, 2012
Senior notes	$ 2,800	$ 1,965
Revolving loans	510	192
Total	3,310	2,157
Less: current portion	—	—
Long-term debt	$ 3,310	$ 2,157
Availability under revolving credit facility:		
Total credit facility limit	$ 1,200	$ 1,150
Revolving loans	(510)	(192)
Letters of credit	(14)	(12)
Total available	$ 676	$ 946

Long-term debt maturities as of December 31, 2013 for each of the next five years are as follows:

Year Ended December 31,	Amount
2014	$ —
2015	—
2016	—
2017	—
2018	600
Thereafter	2,710
Total	$ 3,310

Revolving Credit Facility

In the year ended December 31, 2013, 2012 and 2011 the Partnership borrowed $1.46 billion, $1.56 billion and $940 million, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the same periods, the Partnership repaid $1.1 billion, $1.70 billion and $893 million, respectively, with proceeds from equity offerings and issuances of senior notes.

In May 2013, Regency Gas Services, LP, a wholly-owned subsidiary of Regency Energy Partners LP, entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a “Restricted Subsidiary” structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

The Partnership capitalized $6 million of net loan fees which is being amortized over the remaining term.

The revolving credit facility and the guarantees are senior to the Partnership’s and the guarantors’ unsecured obligations, to the extent of the value of the assets securing such obligations.

As of December 31, 2013, the Partnership was in compliance in all material respects with all of the financial covenants contained within the new credit agreement.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.625% to 1.50% for base rate loans, 1.625% to 2.50% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.17% and 2.93% as of December 31, 2013 and 2012, respectively.

RGS must pay (i) a commitment fee ranging from 0.30% to 0.45% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.625% to 2.50% per annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.00 for the first eight quarters (after March 2015, an increase is allowed in the permitted total leverage ratio for the first two fiscal quarters following any $50 million or greater acquisition), consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2013 and 2012, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extension thereof.

In February 2014, RGS entered into the first Amendment to the Sixth Amended and restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the credit agreement.

Senior Notes

In May 2009, the Partnership and Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership, issued $250 million of senior notes that mature on June 1, 2016 (the "2016 Notes"). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $87 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

The Partnership and Finance Corp. have outstanding the following series of senior notes (collectively "Senior Notes"):

- $600 million in aggregate principal amount of our 6 ⅞% senior notes due December 1, 2018 (the "2018 Notes") with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 5 ¾% senior notes due September 1, 2020 (the "2020 Notes") with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6 ½% senior notes due July 15, 2021 (the "2021 Notes") with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5 ⅞% senior notes due March 1, 2022 (the "2022 Notes") issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5 ½% senior notes due April 15, 2023 (the "2023 5 ½% Notes") with interest payable semi-annually in arrears on April 15 and October 15; and
- $600 million in aggregate principal amount of our 4 ½% senior notes due November 1, 2023 (the "2023 4 ½% Notes") with interest payable semi-annually in arrears on May 1 and November 1.

The Senior Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date.

- 2018 Notes - Beginning December 1, 2014 100% may be redeemed at fixed redemption price of 103.438% (December 1, 2015 - 101.719% and December 1, 2016 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5 ½% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4 ½% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each note holder of the Senior Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. The Partnership's ability to purchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The existing senior notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody's and Standard & Poor's and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2013, we were in compliance with these covenants.

8. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2012	$ 681	$ 60	$ 741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	655	57	712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	$ 629	$ 53	$ 682

The average remaining amortization periods for customer relations and trade names are 24 and 16 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $30 million.

9. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Regency Series A Preferred Units. Derivatives related to commodity swaps are valued using observable inputs for similar instruments and incorporate Level 1 and Level 2 inputs. Embedded derivatives related to the Regency Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31, 2013			Fair Value Measurement at December 31, 2012		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 2	$ 2	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	2	2	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Natural Gas Liquids	4	4	—	1	1	—
Condensate	1	1	—	—	—	—
Embedded Derivatives in Regency Series A Preferred Units	19	—	19	25	—	25
Total Liabilities	$ 28	$ 9	$ 19	$ 31	$ 6	$ 25

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Regency Series A Preferred Units:

Unobservable Input	December 31, 2013
Credit Spread	4.16%
Volatility	23.71%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2013 and 2012. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2013 and 2012.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2012	$ 39
Change in fair value	(14)
Balance at December 31, 2012	25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	$ 19

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2013 was $2.83 billion and $2.80 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.97 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

10. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2013:

For the year ending December 31,	Operating Lease
2014	$ 3
2015	3
2016	2
2017	2
2018	2
Thereafter	34
Total minimum lease payments	$ 46

Total rent expense for operating leases, including those leases with terms of less than one year, was $11 million, $11 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

11. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

The table below reflects the environmental liabilities recorded in the consolidated balance sheet at December 31, 2013 and 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31, 2013	December 31, 2012
Current	$ 2	$ 5
Noncurrent	6	7
Total environmental liabilities	$ 8	$ 12

The Partnership made expenditures related to environmental remediation of $5 million for the year ended December 31, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

CDM Sales Tax Audit. CDM Resource Management LLC ("CDM"), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, the Partnership is unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, none of which are believed to be potentially material to the Partnership at this time.

12. Regency Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Regency Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner's contribution of $2 million. The Regency Series A Preferred Units are convertible to Regency common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value") and accrued interest. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010.

Holders may elect to convert Regency Series A Preferred Units to common units at any time. In July 2013, certain holders of Regency Series A Preferred Units exercised their right to convert 2,459,017 Regency Series A Preferred Units into Regency common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Regency Series A Preferred Units into Regency common units. As of December 31, 2013, the remaining Regency Series A Preferred Units were convertible into 2,050,854 Regency common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership's common unit distributions.

Distributions on the Regency Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of Regency common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Regency Series A Preferred Units, (2) reduces the distributions on the Regency common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions,

such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Regency Series A Preferred Units, all future distributions on the Regency Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Regency Series A Preferred Unit per quarter, (2) $0.09125 per Regency Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Regency Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Regency Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Regency Series A Preferred Units are convertible, at the holder's option, into Regency common units, provided that the holder must request conversion of at least 375,000 Regency Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of Regency common units issuable is equal to the issue price of the Regency Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Regency Series A Preferred Units into Regency common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Regency Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Regency Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2013, the Series A Preferred Units were convertible to 2,050,854 common units.

The following table provides a reconciliation of the beginning and ending balances of the Regency Series A Preferred Units for the year ended December 31, 2013 and 2012:

	Units	Amount	
Balance at January 1, 2012	4,371,586	$ 71	
Accretion to redemption value	N/A	2	
Balance at December 31, 2012	4,371,586	73	
Regency Series A Preferred Units converted into common units	(2,459,017)	(41)	
Balance at December 31, 2013	1,912,569	$ 32	*

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from

partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

13. Related Party Transactions

As of December 31, 2013 and 2012, details of the Partnership's related party receivables and related party payables were as follows:

	December 31, 2013	December 31, 2012
Related party receivables		
HPC	$ 1	$ 1
ETE and its subsidiaries	25	5
Ranch JV	2	2
Total related party receivables	$ 28	$ 8
Related party payables		
HPC	$ 1	$ 1
ETE and its subsidiaries	68	94
Total related party payables	$ 69	$ 95

Transactions with ETE and its subsidiaries. Under the service agreement with ETE Services Company, LLC ("Services Co."), the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, Energy Transfer Company ("ETC"), the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties. The Operation and Service Agreement Amendment describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $11 million for the year ended December 31, 2013, and $17 million for the years ended December 31, 2012 and 2011.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $63 million, $62 million and $57 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2013 and 2012, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

The Partnership's gathering and processing operations, in the ordinary course of business, sells natural gas and NGL to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's contract services operations provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's contract services operations did not sell compression equipment to a subsidiary of ETP for the year ended December 31, 2013, and sold $1 million for the year ended December 31, 2012. As these transactions are between entities under common control, partners' capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's contract services operations purchased compression equipment from a subsidiary of ETP for $95 million and $29 million during the years ended December 31, 2013 and 2012, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided

by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2013, 2012, and 2011, the related party general and administrative expenses reimbursed to the Partnership were $18 million, $20 million, and $17 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's contract services operations provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with Lone Star. In 2013, the Partnership entered into a nineteen month agreement to sell NGL to Lone Star for approximately $5 million per month. For the year ended December 31, 2013, the Partnership had recorded $26 million in NGL sales under this contract.

Transactions with Enterprise Product Partners L.P. and its subsidiaries. In January 2012, Enterprise Products Partners L.P. ("EPD") sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

14. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of Regency's reporting segment.

	Regency Reportable Segment	Years Ended December 31, 2013	2012	2011
Customer				
Customer A	Gathering and Processing	$ 381	$ 367	$ 366
Customer B	Gathering and Processing	362	451	—
Supplier				
Supplier A	Gathering and Processing	164	171	133
Supplier B	Gathering and Processing	185	—	—

Regency is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

15. Regency's Equity-Based Compensation

In December 2011, Regency's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase Regency's common units; awards of Regency's restricted units, Regency phantom units and Regency common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of Regency and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by Regency's Compensation Committee of its board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of Regency's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by Regency's board of directors or its Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of Regency common units available for awards under the plan; however, any material amendment, such as a change in the types of Regency awards available under the plan, would require the Regency's unitholder approval. Regency's Compensation Committee is also authorized to make

adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by Regency's board of directors.

Unit-based compensation expense of $7 million, $5 million, and $3 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2013, 2012 and 2011, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2013, 2012, and 2011 is as follows:

2013

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,550	$ 21.96
Exercised	(14,000)	21.14
Outstanding at end of period	142,550	22.04
Exercisable at the end of the period	142,550	

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 2.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units. In January 2014, the Partnership awarded 668,074 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Distributions on the phantom units will be paid concurrent with the Partnership's distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom unit activity for the years ended December 31, 2013, 2012 and 2011:

2013		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,231,342	$ 23.22
Service condition grants	62,360	25.44
Vested service condition	(231,163)	24.80
Forfeited service condition	(35,900)	23.22
Forfeited market condition	(44,397)	19.52
Total outstanding at end of period	982,242	23.16

2012		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,086,393	$ 24.51
Service condition grants	503,625	21.39
Vested service condition	(223,258)	24.71
Vested market condition	(10,200)	19.52
Forfeited service condition	(120,868)	24.85
Forfeited market condition	(4,350)	19.52
Total outstanding at end of period	1,231,342	23.22

2011		
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	742,517	$ 23.61
Service condition grants	596,320	24.55
Vested service condition	(142,520)	24.73
Vested market condition	(8,550)	19.52
Forfeited service condition	(88,474)	24.99
Forfeited market condition	(12,900)	19.52
Total outstanding at end of period	1,086,393	24.51

The Partnership expects to recognize $19 million of unit-based compensation expense related to non-vested phantom units over a period of 3.3 years.

Exhibit 12.1

ENERGY TRANSFER EQUITY, L.P.

Computation of Ratio of Earnings to Fixed Charges

(in millions, except for ratio amounts)

(Unaudited)

	Years Ended December 31,				
	2013	2012	2011	2010	2009
Fixed charges:					
Interest expense	$ 1,221	$ 1,018	$ 740	$ 625	$ 468
Capitalized interest	45	101	14	29	16
Interest expense included in rental expense	16	6	3	3	3
Distribution to the Series A Convertible Redeemable Preferred Units	6	8	8	4	—
Accretion of the Series A Convertible Redeemable Preferred Units	—	1	—	—	—
Total fixed charges	1,288	1,134	765	661	487
Earnings:					
Income from continuing operations before income taxes	375	1,437	548	358	701
Less: equity in earnings (losses) of affiliates	236	212	117	65	20
Total earnings	139	1,225	431	293	681
Add:					
Fixed charges	1,288	1,134	765	661	487
Amortization of capitalized interest	7	5	4	3	1
Distributed income of equity investees	313	208	117	65	—
Less:					
Interest capitalized	(45)	(101)	(14)	(29)	(16)
Income available for fixed charges	$ 1,702	$ 2,471	$ 1,303	$ 993	$ 1,153
Ratio of earnings to fixed charges	1.32	2.18	1.70	1.50	2.37

Exhibit 21.1

LIST OF SUBSIDIARIES

SUBSIDIARIES OF ENERGY TRANSFER EQUITY, L.P., a Delaware limited partnership:

Eastern Gulf Crude Access, LLC, a Delaware limited liability company
Energy Transfer Crude Oil Company, LLC
Energy Transfer LNG Export, LLC
Energy Transfer Partners GP, L.P., a Delaware limited partnership
Energy Transfer Partners, L.L.C., a Delaware limited liability company
Energy Transfer Partners, L.P., a Delaware limited partnership
ETE Common Holdings Member, LLC, a Delaware limited liability company
ETE Common Holdings, LLC, a Delaware limited liability company
ETE GP Acquirer LLC, a Delaware limited liability company
ETE Services Company, LLC, a Delaware limited liability company
ETE Sigma Holdco, LLC, a Delaware limited liability company
Regency Employees Management Holdings LLC, a Delaware limited liability company
Regency Employees Management LLC, a Delaware limited liability company
Regency Energy Partners LP, a Delaware limited partnership
Regency GP LLC, a Delaware limited liability company
Regency GP LP, a Delaware limited partnership
Sunoco Partners LLC, a Pennsylvania limited liability company
Sunoco Partners Lease Acquisition & Marketing LLC, a Delaware limited liability company
Trunkline LNG Export, LLC

SUBSIDIARIES OF ENERGY TRANSFER PARTNERS, L.P., a Delaware limited partnership:

CCE Acquisition LLC, a Delaware limited liability company
CCE Holdings, LLC, a Delaware limited liability company
Chalkley Gathering Company, LLC, a Texas limited liability company
Citrus Corp., a Delaware corporation
Citrus Energy Services, Inc., a Delaware corporation
Citrus ETP Finance LLC, a Delaware limited liability company
CrossCountry Alaska, LLC, a Delaware limited liability company
CrossCountry Citrus, LLC, a Delaware limited liability company
CrossCountry Energy, LLC, a Delaware limited liability company
Eastern Gulf Crude Access, LLC, a Delaware limited liability company
Energy Transfer Crude Oil Company, LLC, a Delaware limited liability company
Energy Transfer Data Center, LLC, a Delaware limited liability company
Energy Transfer Dutch Holdings, LLC, a Delaware limited liability company
Energy Transfer Employee Management Company, a Delaware corporation
Energy Transfer Fuel GP, LLC, a Delaware limited liability company
Energy Transfer Fuel, LP, a Delaware limited partnership
Energy Transfer Group, LLC, a Texas limited liability company
Energy Transfer International Holdings LLC, a Delaware limited liability company
Energy Transfer Interstate Holdings, LLC, a Delaware limited liability company
Energy Transfer LNG Export, LLC, a Delaware limited liability company
Energy Transfer Mexicana, LLC, a Delaware limited liability company
Energy Transfer Peru LLC, a Delaware limited liability company
Energy Transfer Retail Power, LLC, a Delaware limited liability company
Energy Transfer Technologies, Ltd., a Texas limited partnership
Enhanced Service Systems, Inc., a Delaware corporation
ET Company I, Ltd., a Texas limited partnership
ET Fuel Pipeline, L.P., a Delaware limited partnership
ETC Compression, LLC, a Delaware limited liability company
ETC Endure Energy L.L.C., a Delaware limited liability company
ETC Energy Transfer, LLC, a Delaware limited liability company

ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company
ETC Fayetteville Operating Company, LLC, a Delaware limited liability company
ETC Gas Company, Ltd., a Texas limited partnership
ETC Gathering, LLC, a Texas limited liability company
ETC Hydrocarbons, LLC, a Texas limited liability company
ETC Interstate Procurement Company, LLC, a Delaware limited liability company
ETC Intrastate Procurement Company, LLC, a Delaware limited liability company
ETC Katy Pipeline, Ltd., a Texas limited partnership
ETC Lion Pipeline, LLC, a Delaware limited liability company
ETC M-A Acquisition LLC, a Delaware limited liability company
ETC Marketing, Ltd., a Texas limited partnership
ETC Midcontinent Express Pipeline, L.L.C., a Delaware limited liability company
ETC New Mexico Pipeline, L.P., a New Mexico limited partnership
ETC NGL Marketing, LLC, a Texas limited liability company
ETC NGL Transport, LLC, a Texas limited liability company
ETC Northeast Pipeline, LLC, a Delaware limited liability company
ETC Oasis GP, LLC a Texas limited liability company
ETC Oasis, L.P., a Delaware limited partnership
ETC ProLiance Energy, LLC, an Indiana limited liability company
ETC Texas Pipeline, Ltd., a Texas limited partnership
ETC Tiger Pipeline, LLC, a Delaware limited liability company
ETC Water Solutions, LLC, a Delaware limited liability company
ETE Holdco Corporation, a Delaware corporation
ETP Holdco Corporation, a Delaware corporation
ETP Newco 1 LLC, a Delaware limited liability company
ETP Newco 2 LLC, a Delaware limited liability company
ETP Newco 3 LLC, a Delaware limited liability company
ETP Newco 4 LLC, a Delaware limited liability company
ETP Newco 5 LLC, a Delaware limited liability company
Fayetteville Express Pipeline, LLC, a Delaware limited liability company
FEP Arkansas Pipeline, LLC, an Arkansas limited liability company
Five Dawaco, LLC, a Texas limited liability company
Florida Gas Transmission Company, LLC, a Delaware limited liability company
Heritage ETC GP, L.L.C., a Delaware limited liability company
Heritage ETC, L.P., a Delaware limited partnership
Heritage Holdings, Inc., a Delaware corporation
Houston Pipe Line Company LP, a Delaware limited partnership
HP Houston Holdings, L.P., a Delaware limited partnership
HPL Asset Holdings LP, a Delaware limited partnership
HPL Consolidation LP, a Delaware limited partnership
HPL GP, LLC, a Delaware limited liability company
HPL Holdings GP, L.L.C., a Delaware limited liability company
HPL Houston Pipe Line Company, LLC, a Delaware limited liability company
HPL Leaseco LP, a Delaware limited partnership
HPL Resources Company LP, a Delaware limited partnership
HPL Storage GP LLC, a Delaware limited liability company
LA GP, LLC, a Texas limited liability company
La Grange Acquisition, L.P., a Texas limited partnership
Lake Charles Exports, LLC, a Delaware limited liability company
Lake Charles LNG Exports, LLC, a Delaware limited liability company
Leapartners, L.P., a Texas limited partnership
Lee 8 Storage Partnership, a Delaware limited partnership
LG PL, LLC, a Texas limited liability company
LGM, LLC, a Texas limited liability company
Liberty Pipeline Group, LLC, a Delaware limited liability company
Lone Star NGL LLC, a Delaware limited liability company
Lone Star NGL Asset Holdings LLC, a Delaware limited liability company

Lone Star NGL Asset Holdings II LLC, a Delaware limited liability company

Lone Star NGL Asset GP LLC, a Delaware limited liability company
Lone Star NGL Development LP, a Delaware limited partnership
Lone Star NGL Pipeline LP, a Delaware limited partnership
Lone Star NGL Product Services LLC, a Delaware limited liability company
Lone Star NGL Hattiesburg LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu GP LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu LP, a Delaware limited partnership
Lone Star NGL Hastings LLC, a Delaware limited liability company
Lone Star NGL Refinery Services LLC, a Delaware limited liability company
Lone Star NGL Sea Robin LLC, a Delaware limited liability company
Lone Star NGL Fractionators LLC, a Delaware limited liability company
Lone Star NGL Marketing LLC, a Delaware limited liability company
MACS Retail LLC, a Virginia limited liability company
Mid-Atlantic Convenience Stores, LLC, a Delaware limited liability company
Oasis Partner Company, a Delaware corporation
Oasis Pipe Line Company Texas L.P., a Texas limited partnership
Oasis Pipe Line Company, a Delaware corporation
Oasis Pipe Line Finance Company, a Delaware corporation
Oasis Pipe Line Management Company, a Delaware corporation
Oasis Pipeline, LP, a Texas limited partnership
Pan Gas Storage LLC , a Delaware limited liability company
Panhandle Eastern Pipe Line Company, LP, a Delaware limited partnership
Panhandle Energy LNG Services, LLC, a Delaware limited liability company
Panhandle Holdings LLC, a Delaware limited liability company
Panhandle Storage LLC, a Delaware limited liability company
PEI Power Corporation, a Pennsylvania corporation
PEI Power II, LLC, a Pennsylvania corporation
PG Energy, Inc., a Pennsylvania corporation
Rich Eagleford Mainline, LLC, a Delaware limited liability company
Sea Robin Pipeline Company, LLC , a Delaware limited liability company
SEC Energy Products & Services, L.P., a Texas limited partnership
SEC Energy Realty GP, LLC, a Texas limited liability company
SEC General Holdings, LLC, a Texas limited liability company
SEC-EP Realty Ltd., a Texas limited partnership
Southern Union Gas Company, Inc., a Texas corporation
Southern Union Panhandle LLC, a Delaware limited liability company
Southside Oil, LLC, a Virginia limited liability company
SU Gas Services Operating Company, Inc., a Delaware corporation
SU Holding Company, Inc., a Delaware corporation
SU Pipeline Management LP, a Delaware limited partnership
SUCo LLC, a Delaware limited liability company
SUCo LP, a Delaware limited partnership
SUGAir Aviation Company, a Delaware corporation
SUG Holdings, LLC , a Delaware limited liability company
Sunoco Logistic Partners L.P. , a Delaware limited partnership
Sunoco Inc., a Pennsylvania corporation
Sunoco Partners LLC, a Pennsylvania limited liability company
TETC, LLC, a Texas limited liability company
Texas Energy Transfer Company, Ltd., a Texas limited partnership
Texas Energy Transfer Power, LLC, a Texas limited liability company
Transwestern Pipeline Company, LLC, a Delaware limited liability company
Trunkline Deepwater Pipeline LLC, a Delaware limited liability company
Trunkline Field Services LLC, a Delaware limited liability company
Trunkline Gas Company, LLC, a Delaware limited liability company
Trunkline LNG Company, LLC, a Delaware limited liability company
Trunkline LNG Export, LLC , a Delaware limited liability company
Trunkline LNG Holdings LLC, a Delaware limited liability company

Trunkline Offshore Pipeline LLC, a Delaware limited liability company

Whiskey Bay Gas Company, Ltd., a Texas limited partnership
Whiskey Bay Gathering Company, LLC, a Delaware limited liability company

SUBSIDIARIES OF REGENCY ENERGY PARTNERS LP, a Delaware limited partnership:

Regency OLP GP LLC, a Delaware limited liability company
Regency Energy Finance Corp., a Delaware corporation
Regency Gas Services LP, a Delaware limited partnership
Regency Field Services LLC, a Delaware limited liability company
Edwards Lime Gathering, LLC, a Delaware limited liability company
Regency Liquids Pipeline LLC, a Delaware limited liability company
Gulf States Transmission LLC, a Louisiana limited liability company
Regency Gas Utility LLC, a Delaware limited liability company
Pueblo Holdings, Inc., a Delaware corporation
Pueblo Midstream Gas Corporation, a Texas corporation
CDM Resource Management LLC, a Delaware limited liability company
FrontStreet Hugoton LLC, a Delaware limited liability company
WGP-KHC, LLC, a Delaware limited liability company
Regency Haynesville Intrastate Gas LLC, a Delaware limited liability company
RIGS Haynesville Partnership Co., a Delaware partnership
RIGS GP LLC, a Delaware limited liability company
Regency Intrastate Gas LP, a Delaware limited partnership
Regency Midcontinent Express LLC, a Delaware limited liability company
Midcontinent Express Pipeline LLC, a Delaware limited liability company
Regency Texas Pipeline LLC, a Delaware limited liability company
Lone Star NGL LLC, a Delaware limited liability company
Regency Ranch JV LLC, a Delaware limited liability company
Ranch Westex JV LLC, a Delaware limited liability company
ELG Oil LLC, a Delaware limited liability company
ELG Utility LLC, a Delaware limited liability company
RGU West LLC, a Texas limited liability company
RGP Westex Gatering Inc., a Texas corporation
RGP Marketing LLC, a Texas limited liability company
RHEP Crude LLC, a Texas limited liability company
West Texas Gathering Company, a Delaware corporation

SUBSIDIARIES OF SUNOCO, INC., a Pennsylvania corporation

Atlantic Petroleum (Out) LLC, a Delaware limited liability company
Atlantic Petroleum Corporation, a Delaware corporation
Atlantic Petroleum Delaware Corporation , a Delaware corporation
Atlantic Pipeline (Out) L.P. Texas limited partnership
Atlantic Refining & Marketing Corp., a Delaware corporation
Aventine Renewable Energy Holdings, Inc., a Delaware corporation
Clean Air Action Corporation, a Delaware corporation
Evergreen Assurance, LLC, a Delaware limited liability company
Evergreen Capital Holdings, LLC, a Delaware limited liability company
Evergreen Resources Group, LLC, a Delaware limited liability company
Helios Assurance Company, a Limited Bermuda other
Jalisco Corporation, a California corporation
Japan Sun Oil Company, Ltd., a Japan other
Lavan Petroleum Company (LAPCO), an Iran, Islamic Republic of other
Lesley Corporation, a Delaware corporation
Libre Insurance Company, Ltd., a Bermuda other
Lugrasa, S.A., a Panama corporation
Mascot, Inc. (MA), a Massachusetts corporation
Mid-Continent Pipe Line (Out) LLC, a Texas limited liability company
Oil Casualty Insurance, Ltd., a Bermuda other
Oil Insurance Limited, Bermuda limited company

Pacesetter/MVHC, Inc., a Texas corporation
PES Holdings, LLC, a Delaware limited liability company
Philadelphia Energy Solutions LLC, a Delaware limited liability company
Philadelphia Energy Solutions Refining and Marketing LLC, a Delaware limited liability company
Puerto Rico Sun Oil Company LLC, a Delaware limited liability company
Sun Alternate Energy Corporation, a Delaware corporation
Sun Atlantic Refining and Marketing B.V., a Netherlands other
Sun Atlantic Refining and Marketing B.V., Inc., a Delaware corporation
Sun Atlantic Refining and Marketing Company, a Delaware corporation
Sun Canada, Inc., a Delaware corporation
Sun Company, Inc., a Delaware corporation
Sun Company, Inc., a Pennsylvania corporation
Sun International Limited, a Bermuda other
Sun Lubricants and Specialty Products Inc., a Quebec corporation
Sun Mexico One, Inc., a Delaware corporation
Sun Mexico Two, Inc., a Delaware corporation
Sun Oil Company, a Delaware corporation
Sun Oil Export Company, a Delaware corporation
Sun Oil International, Inc., a Delaware corporation
Sun Petrochemicals, Inc., a Delaware corporation
Sun Pipe Line Company, a Texas corporation
Sun Pipe Line Delaware (Out) LLC, a Delaware limited liability company
Sun Refining and Marketing Company, a Delaware corporation
Sun Services Corporation, a Pennsylvania corporation
Sun Transport, LLC, a Pennsylvania limited liability company
Sun-Del Pipeline LLC, a Delaware limited liability company
Sun-Del Services, Inc., a Delaware corporation
Sunmarks, LLC, a Delaware limited liability company
Sunoco de Mexico, S.A. de C.V., a Mexico other
Sunoco Overseas, Inc., a Delaware corporation
Sunoco Power Marketing L.L.C., a Pennsylvania limited liability company
Sunoco Receivables Corporation, Inc., a Delaware corporation
Sunoco, Inc. (R&M), a Pennsylvania corporation
Sunoco, LLC, a Delaware limited liability company
The New Claymont Investment Company, a Delaware corporation
The Sunoco Foundation, a Pennsylvania not-for-profit corporation
Venezoil, C.A., a Venezuela other

SUBSIDIARIES OF SUNOCO LOGISTICS PARTNERS L.P., a Delaware limited partnership

Excel Pipeline LLC, a Delaware limited liability company
Inland Corporation, an Ohio corporation
Mid-Valley Pipeline Company, an Ohio corporation
Sun Pipe Line Company of Delaware LLC, a Delaware limited liability company
Sunoco Lease Acquisition & Marketing LLC, a Delaware limited liability company
Sunoco Logistics Partners GP LLC, a Delaware limited liability company
Sunoco Logistics Partners L.P., a Delaware limited partnership
Sunoco Logistics Partners Operations GP LLC, a Delaware limited liability company
Sunoco Logistics Partners Operations L.P., a Delaware limited partnership
Sunoco Partners Marketing & Terminals L.P., a Texas limited partnership
Sunoco Partners NGL Facilities LLC, a Delaware limited liability company
Sunoco Partners Operating LLC, a Delaware limited liability company
Sunoco Partners Real Estate Acquisition LLC, a Delaware limited liability company
Sunoco Partners Rockies LLC, a Delaware limited liability company
Sunoco Pipeline Acquisition LLC, a Delaware limited liability company
Sunoco Pipeline L.P., a Texas limited partnership
West Texas Gulf Pipe Line Company, a Delaware corporation

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 27, 2014, with respect to the consolidated financial statements and internal control over financial reporting of Energy Transfer Equity, L.P. included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the financial statements of ETE Common Holdings, LLC included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Energy Transfer Partners, L.P. included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Energy Transfer Partners GP, L.P. included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Regency Energy Partners LP included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.6

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Regency GP LP included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.7

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of ETE GP Acquirer LLC included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.8

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of RIGS Haynesville Partnership Co. incorporated by reference in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.9

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Lone Star NGL LLC incorporated by reference in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.10

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement on Form S-3 No. 333-192327 of Energy Transfer Equity, L.P.
(2) Registration Statement on Form S-3 No. 333-146300 of Energy Transfer Equity, L.P.
(3) Registration Statement on Form S-8 No. 333-146298 pertaining to the Employees' Savings Plan of Energy Transfer Equity, L.P.

of our report dated March 1, 2013, with respect to the consolidated financial statements of Sunoco Logistics Partners L.P., included in this Annual Report (Form 10-K) of Energy Transfer Equity, L.P. for the year ended December 31, 2013.

/s/Ernst & Young LLP

Philadelphia, Pennsylvania
February 27, 2014

Exhibit 23.11

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-146300), on Form S-3 ASR (No. 333-192327) and on Form S-8 (No. 333-146298) of Energy Transfer Equity, L.P of our reports dated February 21, 2014 and February 19, 2013 relating to the financial statements of Midcontinent Express Pipeline LLC, which appear in Exhibits 99.3 and 99.4 of the 2013 Annual Report on Form 10-K of Regency Energy Partners LP, which is incorporated in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2014

Exhibit 31.1

CERTIFICATION OF PRESIDENT (PRINCIPAL EXECUTIVE OFFICER)
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John W. McReynolds, certify that:

1. I have reviewed this annual report on Form 10-K of Energy Transfer Equity, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2014

/s/ John W. McReynolds

John W. McReynolds
President

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jamie Welch, certify that:

1. I have reviewed this quarterly report on Form 10-K of Energy Transfer Equity, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2014

/s/ Jamie Welch

Jamie Welch
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Energy Transfer Equity, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John W. McReynolds, President, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 27, 2014

/s/ John W. McReynolds

John W. McReynolds
President

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer Equity, L.P. and furnished to the Securities and Exchange Commission upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer Equity, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jamie Welch, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 27, 2014

/s/ Jamie Welch

Jamie Welch
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer Equity, L.P. and furnished to the Securities and Exchange Commission upon request.

Exhibit 99.1

REPORT OF ERNST & YOUNG LLP, INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENTS

To the Board of Directors of
Sunoco Partners LLC and Limited Partners of Sunoco Logistics Partners L.P.

We have audited the accompanying consolidated balance sheets of Sunoco Logistics Partners L.P. (the "Partnership") as of December 31, 2012 (successor), and the related consolidated statements of comprehensive income, equity, and cash flows for the period from October 5, 2012 to December 31, 2012 (successor), the period from January 1, 2012 to October 4, 2012 (predecessor) and the year ended December 31, 2011 (predecessor). 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 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 provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Sunoco Logistics Partners L.P. at December 31, 2012 (successor) and the consolidated results of its operations and its cash flows for the period from October 5, 2012 to December 31, 2012 (successor), the period from January 1, 2012 to October 4, 2012 (predecessor) and the year ended December 31, 2011 (predecessor), in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
March 1, 2013