Energy Transfer Partners, L.P.
Form 10-Q
August 05, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 1-11727
ENERGY TRANSFER PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

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

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)
(214) 981-0700
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
At July 29, 2016, the registrant had 523,519,262 Common Units outstanding.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (the "Partnership," or "ETP") in periodic press releases and some oral statements of the Partnership's officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect," "continue," "estimate," "goal," " "may," "will" or similar expressions help identify forward-looking statements. Although the Partnership and its general partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see "Part I – Item 1A. Risk Factors" in the Partnership's Report on Form 10-K for the year ended December 31, 2015 filed with the Securities and Exchange Commission on February 29, 2016.

Definitions

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

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Bbls	barrels
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
Citrus	Citrus, LLC
CrossCountry	CrossCountry Energy, LLC
EPA	Environmental Protection Agency
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC MEP	ETC Midcontinent Express Pipeline, L.L.C.
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company

ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ET Interstate	Energy Transfer Interstate Holdings, LLC
ET Rover	ET Rover Pipeline LLC
ETP Credit Facility	ETP’s $3.75 billion revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission

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FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	incentive distribution rights
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a subsidiary of ETE
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC
MEP	Midcontinent Express Pipeline LLC
MMBtu	million British thermal units
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PES	Philadelphia Energy Solutions, a refining joint venture
PHMSA	Pipeline Hazardous Materials Safety Administration
Preferred Units	ETP Series A cumulative convertible preferred units
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a joint venture between subsidiaries of ETC OLP and Sunoco, Inc.
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
SEC	Securities and Exchange Commission

Southern Union	Southern Union Company
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco LP	Sunoco LP (previously named Susser Petroleum Partners, LP)
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle

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

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

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$386	$ 527
Accounts receivable, net	2,542	2,118
Accounts receivable from related companies	354	268
Inventories	1,425	1,213
Derivative assets	35	40
Other current assets	587	532
Total current assets	5,329	4,698
Property, plant and equipment	53,421	50,869
Accumulated depreciation and depletion	(6,434)	(5,782)
	46,987	45,087
Advances to and investments in unconsolidated affiliates	5,018	5,003
Non-current derivative assets	18	—
Other non-current assets, net	518	536
Intangible assets, net	4,032	4,421
Goodwill	4,139	5,428
Total assets	$66,041	$ 65,173

The accompanying notes are an integral part of these consolidated financial statements.
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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	June 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$2,493	$ 1,859
Accounts payable to related companies	21	25
Derivative liabilities	23	63
Accrued and other current liabilities	1,815	2,048
Current maturities of long-term debt	1,007	126
Total current liabilities	5,359	4,121
Long-term debt, less current maturities	27,950	28,553
Long-term notes payable – related companies	182	233
Non-current derivative liabilities	367	137
Deferred income taxes	4,471	4,082
Other non-current liabilities	961	968
Commitments and contingencies		
Series A Preferred Units	33	33
Redeemable noncontrolling interests	15	15
Equity:		
General Partner	234	306
Limited Partners:		
Common Unitholders	16,024	17,043
Class H Unitholder	3,474	3,469
Class I Unitholder	2	14
Accumulated other comprehensive income (loss)	(6)	4
Total partners’ capital	19,728	20,836
Noncontrolling interest	6,975	6,195
Total equity	26,703	27,031
Total liabilities and equity	$66,041	$ 65,173

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES:				
Natural gas sales	$695	$899	$1,533	$1,933
NGL sales	1,150	988	2,090	1,969
Crude sales	1,713	2,680	2,923	4,888
Gathering, transportation and other fees	1,045	980	2,005	1,973
Refined product sales (see Note 2)	234	4,434	479	8,090
Other (see Note 2)	452	1,559	740	3,013
Total revenues	5,289	11,540	9,770	21,866
COSTS AND EXPENSES:				
Cost of products sold (see Note 2)	3,630	9,354	6,598	17,850
Operating expenses (see Note 2)	374	635	722	1,245
Depreciation, depletion and amortization	496	501	966	980
Selling, general and administrative (see Note 2)	74	162	155	295
Total costs and expenses	4,574	10,652	8,441	20,370
OPERATING INCOME	715	888	1,329	1,496
OTHER INCOME (EXPENSE):				
Interest expense, net	(317)	(336)	(636)	(646)
Equity in earnings of unconsolidated affiliates	119	117	195	174
Losses on extinguishments of debt	—	(33)	—	(33)
Gains (losses) on interest rate derivatives	(81)	127	(151)	50
Other, net	27	17	44	24
INCOME BEFORE INCOME TAX BENEFIT	463	780	781	1,065
Income tax benefit	(9)	(59)	(67)	(42)
NET INCOME	472	839	848	1,107
Less: Net income attributable to noncontrolling interest	102	212	167	206
Less: Net loss attributable to predecessor	—	(27)	—	(34)
NET INCOME ATTRIBUTABLE TO PARTNERS	370	654	681	935
General Partner’s interest in net income	223	260	520	502
Class H Unitholder’s interest in net income	85	64	164	118
Class I Unitholder’s interest in net income	2	32	4	65
Common Unitholders’ interest in net income (loss)	$60	$298	$(7)	$250
NET INCOME (LOSS) PER COMMON UNIT:				
Basic	$0.10	$0.67	$(0.05)	$0.63
Diluted	$0.10	$0.67	$(0.05)	$0.63

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income	$472	$839	$848	$1,107
Other comprehensive income (loss), net of tax:				
Change in value of derivative instruments accounted for as cash flow hedges	—	—	—	1
Change in value of available-for-sale securities	3	(1)	5	—
Actuarial gain (loss) relating to pension and other postretirement benefit plans	6	—	(3)	45
Foreign currency translation adjustments	—	—	(1)	(2)
Change in other comprehensive income from unconsolidated affiliates	(5)	—	(11)	(2)
	4	(1)	(10)	42
Comprehensive income	476	838	838	1,149
Less: Comprehensive income attributable to noncontrolling interest	102	212	167	206
Less: Comprehensive loss attributable to predecessor	—	(27)	—	(34)
Comprehensive income attributable to partners	$374	$653	$671	$977

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2016
(Dollars in millions)
(unaudited)

		Limited Partners					
	General Partner	Common Units	Class H Units	Class I Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2015	$ 306	$ 17,043	$ 3,469	$ 14	$ 4	$ 6,195	$ 27,031
Distributions to partners	(592)	(1,046)	(159)	(16)	—	—	(1,813)
Distributions to noncontrolling interest	—	—	—	—	—	(209)	(209)
Units issued for cash	—	408	—	—	—	—	408
Subsidiary units issued for cash	—	14	—	—	—	653	667
Capital contributions from noncontrolling interest	—	—	—	—	—	161	161
Sunoco, Inc. retail business to Sunoco LP transaction	—	(405)	—	—	—	—	(405)
Other comprehensive loss, net of tax	—	—	—	—	(10)	—	(10)
Other, net	—	17	—	—	—	8	25
Net income (loss)	520	(7)	164	4	—	167	848
Balance, June 30, 2016	$ 234	$ 16,024	$ 3,474	$ 2	$ (6)	$ 6,975	$ 26,703

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

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

	Six Months Ended June 30, 2016			2015		
OPERATING ACTIVITIES						
Net income	$	848		$	1,107	
Reconciliation of net income to net cash provided by operating activities:						
Depreciation, depletion and amortization	966			980		
Deferred income taxes	(79		)	79		
Amortization included in interest expense	(12		)	(21		)
Inventory valuation adjustments	(106		)	(150		)
Unit-based compensation expense	38			43		
Losses on extinguishments of debt	—			33		
Distributions on unvested awards	(13		)	(7		)
Equity in earnings of unconsolidated affiliates	(195		)	(174		)
Distributions from unconsolidated affiliates	199			162		
Other non-cash	(124		)	19		
Net change in operating assets and liabilities, net of effects of acquisition	(96		)	(938		)
Net cash provided by operating activities	1,426			1,133		
INVESTING ACTIVITIES						
Proceeds from the Sunoco, Inc. retail business to Sunoco LP transaction	2,200			—		
Proceeds from Bakken Pipeline Transaction	—			980		
Proceeds from sale of noncontrolling interest	—			64		
Cash paid for acquisition of a noncontrolling	—			(129		)

interest				
Cash paid for all other acquisitions	—		(475	)
Capital expenditures, excluding allowance for equity funds used during construction	(3,479	)	(4,143	)
Contributions in aid of construction costs	25		12	
Contributions to unconsolidated affiliates	(31	)	(43	)
Distributions from unconsolidated affiliates in excess of cumulative earnings	56		64	
Proceeds from the sale of assets	7		15	
Change in restricted cash	(2	)	8	
Other	(1	)	(9	)
Net cash used in investing activities	(1,225	)	(3,656	)
FINANCING ACTIVITIES				
Proceeds from borrowings	7,811		12,494	
Repayments of long-term debt	(7,514	)	(9,386	)
Proceeds from borrowings from affiliates	147		—	
Units issued for cash	408		724	
Subsidiary units issued for cash	667		1,013	
Predecessor units issued for cash	—		34	
Capital contributions from noncontrolling interest	161		398	
Distributions to partners	(1,813	)	(1,384	)
Predecessor distributions to partners	—		(202	)
Distributions to noncontrolling interest	(209	)	(165	)
Debt issuance costs	—		(50	)
Other	—		(1	)
Net cash provided by (used in) financing activities	(342	)	3,475	
Increase (decrease) in cash and cash equivalents	(141	)	952	
	527		663	

Cash and cash equivalents, beginning of period				
Cash and cash equivalents, end of period	$	386	$	1,615

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

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

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

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

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.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.
- ETC MEP, a Delaware limited liability company that directly owns a 50% interest in MEP.
- ETC Compression, LLC, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- ETP Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco, Inc. Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. Sunoco, Inc. owned and operated retail marketing assets, which were contributed to Sunoco LP in March 2016, as discussed in Note 2. Subsequent to this transaction, Sunoco Inc.’s assets primarily consist of its ownership in Retail Holdings, which owns noncontrolling interests in Sunoco LP and PES.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary crude oil, NGLs, and refined products pipeline, terminalling, and acquisition and marketing assets which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.
- Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP LLC, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, and in exchange, ETE transferred to ETP 21 million ETP common units. These operations were reported within the retail marketing segment. In connection with this transaction, the Partnership deconsolidated Sunoco LP, and its remaining investment in Sunoco LP is accounted for under the equity method. Additionally, in March 2016 and as discussed in Note 2, ETP contributed to Sunoco LP its remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business effective January 1, 2016.

Our financial statements reflect the following reportable business segments:

- intrastate transportation and storage;
- interstate transportation and storage;

- midstream;
- liquids transportation and services;

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- investment in Sunoco Logistics;
- retail marketing; and
- all other.

Basis of Presentation

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

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

Merger with Regency. On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency surviving as a wholly-owned subsidiary of the Partnership (the "Regency Merger"). The Regency Merger was a combination of entities under common control; therefore, Regency's assets and liabilities were not adjusted. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner).

Use of Estimates

The unaudited consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions made 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 consolidated 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.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In August 2015, the FASB deferred the effective date of ASU 2014-09, which is now effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is permitted as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within those annual periods. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis ("ASU 2015-02"), which changed the requirements for consolidations analysis. Under ASU 2015-02, reporting entities are required to evaluate whether they should consolidate certain legal entities. The Partnership adopted this standard on January 1, 2016, and the adoption did not impact the Partnership's financial position or results of operations.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which establishes the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. The Partnership is currently evaluating the impact, if any, that adopting this new standard will have on the consolidated financial statements and related disclosures.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Stock Compensation (Topic 718) ("ASU 2016-09"). The objective of the update is to reduce complexity in accounting standards. The areas for simplification in this update involve several aspects of the accounting for employee share-based payment transactions, including the income tax

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consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. In addition, the amendments in this update eliminate the guidance in Topic 718 that was indefinitely deferred shortly after the issuance of FASB Statement No. 123 (revised 2004), Share-Based Payment. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted. The Partnership is currently evaluating the impact that it will have on the consolidated financial statements and related disclosures.

2. CONTRIBUTION TRANSACTION

Sunoco Retail to Sunoco LP

In March 2016, ETP contributed to Sunoco LP its remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP paid $2.20 billion in cash, including a working capital adjustment, and issued 5.7 million Sunoco LP common units to Retail Holdings, a wholly-owned subsidiary of the Partnership. The transaction was effective January 1, 2016. In connection with this transaction, the Partnership deconsolidated the legacy Sunoco, Inc. retail business, including goodwill of $1.29 billion and intangible assets of $294 million. The results of Sunoco, LLC and the legacy Sunoco, Inc. retail business' operations have not been presented as discontinued operations and Sunoco, Inc.'s retail business assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements.

Impact of Contribution Transactions

Following is a summary of amounts reflected in ETP's consolidated statements of operations related to Sunoco, LLC and the legacy Sunoco, Inc. retail business, which operations are no longer consolidated for the three and six months ended June 30, 2016:

	Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
Revenues	$ 5,537	$ 10,342
Cost of products sold	5,003	9,370
Operating expenses	281	552
Selling, general and administrative expenses	58	93

3. CASH AND CASH EQUIVALENTS

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

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

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

	Six Months Ended June 30, 2016	2015
Accounts receivable	$(471)	$82
Accounts receivable from related companies	(129)	(53)
Inventories	(157)	(252)
Other current assets	(53)	(110)
Other non-current assets, net	8	99
Accounts payable	509	(333)
Accounts payable to related companies	21	(262)
Accrued and other current liabilities	(22)	(169)
Other non-current liabilities	20	30
Derivative assets and liabilities, net	178	30
Net change in operating assets and liabilities, net of effects of acquisition	$(96)	$(938)

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2016	2015
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$861	$693
Sunoco LP limited partner interest received in exchange for contribution of the Sunoco, Inc. retail business to Sunoco LP	194	—
Net gains from subsidiary common unit issuances	14	102
NON-CASH FINANCING ACTIVITIES:		
Issuance of common units in connection with the Regency Merger	$—	$9,250
Issuance of Class H Units in connection with the Bakken Pipeline Transaction	—	1,946
Redemption of common units in connection with the Bakken Pipeline Transaction	—	999

4. INVENTORIES

Inventories consisted of the following:

	June 30, 2016	December 31, 2015
Natural gas and NGLs	$552	$ 415
Crude oil	564	424
Refined products	106	104
Other	203	270
Total inventories	$1,425	$ 1,213

We utilize commodity derivatives to manage price volatility associated with our natural gas inventories stored in our Bammel storage facility. 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.

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5. FAIR VALUE MEASURES

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 consolidated debt obligations as of June 30, 2016 was $29.25 billion and $28.96 billion, respectively. As of December 31, 2015, the aggregate fair value and carrying amount of our consolidated debt obligations was $25.71 billion and $28.68 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, interest rate derivatives and embedded derivatives in the Preferred Units 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. Derivatives related to the embedded derivatives in our 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 value, and are considered Level 3. During the six months ended June 30, 2016, no transfers were made between any levels within the fair value hierarchy.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2016 and December 31, 2015 based on inputs used to derive their fair values:

	Fair Value Measurements at June 30, 2016			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$29	$ —	$ 29	$ —
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	18	18	—	—
Swing Swaps IFERC	6	—	6	—
Fixed Swaps/Futures	41	41	—	—
Forward Physical Swaps	4	—	4	—
Power:				
Forwards	30	—	30	—
Options – Calls	3	3	—	—
Natural Gas Liquids – Forwards/Swaps	76	76	—	—
Refined Products – Futures	1	1	—	—
Crude – Futures	5	5	—	—
Total commodity derivatives	184	144	40	—
Total assets	$213	$ 144	$ 69	$ —
Liabilities:				
Interest rate derivatives	$(358)	$ —	$ (358)	$ —
Embedded derivatives in the Preferred Units	(9)	—	—	(9)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(17)	(17)	—	—
Swing Swaps IFERC	(6)	(1)	(5)	—
Fixed Swaps/Futures	(64)	(64)	—	—
Forward Physical Swaps	(2)	—	(2)	—
Power:				
Forwards	(28)	—	(28)	—
Futures	(1)	(1)	—	—
Natural Gas Liquids – Forwards/Swaps	(88)	(88)	—	—
Refined Products – Futures	(9)	(9)	—	—
Crude – Futures	(7)	(7)	—	—
Total commodity derivatives	(222)	(187)	(35)	—
Total liabilities	$(589)	$ (187)	$ (393)	$ (9)

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	Fair Value Total	Fair Value Measurements at December 31, 2015 Level 1	Level 2	Level 3
Assets:				
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	$ 16	$ 16	$ —	$ —
Swing Swaps IFERC	10	2	8	—
Fixed Swaps/Futures	274	274	—	—
Forward Physical Swaps	4	—	4	—
Power:				
Forwards	22	—	22	—
Futures	3	3	—	—
Options – Puts	1	1	—	—
Options – Calls	1	1	—	—
Natural Gas Liquids – Forwards/Swaps	99	99	—	—
Refined Products – Futures	9	9	—	—
Crude – Futures	9	9	—	—
Total commodity derivatives	448	414	34	—
Total assets	$ 448	$ 414	$ 34	$ —
Liabilities:				
Interest rate derivatives	$ (171)	$ —	$ (171)	$ —
Embedded derivatives in the Preferred Units	(5)	—	—	(5)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(16)	(16)	—	—
Swing Swaps IFERC	(12)	(2)	(10)	—
Fixed Swaps/Futures	(203)	(203)	—	—
Power:				
Forwards	(22)	—	(22)	—
Futures	(2)	(2)	—	—
Options – Puts	(1)	(1)	—	—
Natural Gas Liquids – Forwards/Swaps	(89)	(89)	—	—
Crude – Futures	(5)	(5)	—	—
Total commodity derivatives	(350)	(318)	(32)	—
Total liabilities	$ (526)	$ (318)	$ (203)	$ (5)

The following table presents a reconciliation of the beginning and ending balances for our Level 3 financial instruments measured at fair value on a recurring basis using significant unobservable inputs for the six months ended June 30, 2016.

Balance, December 31, 2015	$(5)
Net unrealized gains included in other income (expense)	(4)
Balance, June 30, 2016	$(9)

6. NET INCOME (LOSS) PER LIMITED PARTNER UNIT

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 the General Partner, the holder of the IDRs pursuant to the Partnership Agreement, which

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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. Loss attributable to predecessor represents amounts allocated to the former Regency partners and have no impact on net income (loss) per unit for the periods prior to the Regency Merger.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income	$472	$839	$848	$1,107
Less: Income attributable to noncontrolling interest	102	212	167	206
Less: Loss attributable to predecessor	—	(27)	—	(34)
Net income, net of noncontrolling interest and predecessor income	370	654	681	935
General Partner's interest in net income	223	260	520	502
Class H Unitholder's interest in net income	85	64	164	118
Class I Unitholder's interest in net income	2	32	4	65
Common Unitholders' interest in net income (loss)	60	298	(7)	250
Additional earnings allocated to General Partner	(3)	(2)	(6)	(4)
Distributions on employee unit awards, net of allocation to General Partner	(5)	(3)	(10)	(7)
Net income (loss) available to Common Unitholders	$52	$293	$(23)	$239
Weighted average Common Units – basic[(1)]	501.6	434.8	495.9	379.6
Basic net income (loss) per Common Unit	$0.10	$0.67	$(0.05)	$0.63
Net income (loss) available to Common Unitholders	$52	$293	$(23)	$239
Income attributable to Preferred Units	(4)	—	(3)	—
Diluted net income (loss) available to Common Unitholders	$48	$293	$(26)	$239
Weighted average Common Units – basic[(1)]	501.6	434.8	495.9	379.6
Dilutive effect of unvested employee unit awards	0.7	1.5	—	1.5
Dilutive effect of Preferred Units	0.4	—	0.4	—
Weighted average Common Units – diluted[(1)]	502.7	436.3	496.3	381.1
Diluted net income (loss) per Common Unit	$0.10	$0.67	$(0.05)	$0.63

(1) Excludes Common Units owned by the Partnership's consolidated subsidiaries.

7. DEBT OBLIGATIONS

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $3.75 billion and expires in November 2019. The indebtedness under the ETP Credit Facility is unsecured, is not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. As of June 30, 2016, the ETP Credit Facility had $1.13 billion of outstanding borrowings.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $2.50 billion unsecured revolving credit agreement (the "Sunoco Logistics Credit Facility"), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total

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aggregate commitment may be increased to $3.25 billion under certain conditions. As of June 30, 2016, the Sunoco Logistics Credit Facility had $1.26 billion of outstanding borrowings.

ETP Senior Notes

Subsequent to the Regency Merger in 2015, ETP assumed $3.80 billion total aggregate principal amount of Regency's senior notes, which remained outstanding as of June 30, 2016. These notes were previously guaranteed by certain consolidated subsidiaries that had previously been consolidated by Regency. The subsidiary guarantees on all of these outstanding notes have been released.

Sunoco Logistics Senior Notes

Sunoco Logistics had $175 million of 6.125% senior notes which matured and were repaid in May 2016, using borrowings under the $2.50 billion Sunoco Logistics Credit Facility.

In July 2016, Sunoco Logistics issued $550 million aggregate principal amount of 3.90% senior notes due in July 2026. The net proceeds from this offering were used to repay outstanding credit facility borrowings and for general partnership purposes.

Bakken Financing

In August 2016, ETP, Sunoco Logistics and Phillips 66 announced the completion of the project-level financing of the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline projects (collectively, the "Bakken Pipeline"). The $2.50 billion facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of June 30, 2016.

8. EQUITY

ETP

The changes in outstanding common units during the six months ended June 30, 2016 were as follows:

	Number of Units
Number of common units at December 31, 2015	505.6
Common units issued in connection with equity distribution agreements	11.2
Common units issued in connection with the distribution reinvestment plan	3.1
Number of common units at June 30, 2016	519.9

During the six months ended June 30, 2016, the Partnership received proceeds of $324 million, net of $3 million commissions, from the issuance of common units pursuant to equity distribution agreements, which were used for general partnership purposes. As of June 30, 2016, none of the Partnership's common units were available to be issued under an equity distribution agreement. In July 2016, the Partnership entered into an equity distribution agreement with an aggregate offering price up to $1.50 billion.

During the six months ended June 30, 2016, distributions of $84 million were reinvested under the distribution reinvestment plan. As of June 30, 2016, a total of 8.4 million common units remain available to be issued under the existing registration statement in connection with the distribution reinvestment plan.

Sunoco Logistics

During the six months ended June 30, 2016, Sunoco Logistics received proceeds of $667 million, net of $7 million commissions and fees, from the issuance of Sunoco Logistics common units pursuant to equity distribution agreements, which were used for general partnership purposes. As a result of Sunoco Logistics' issuances of common units during the six months ended June 30, 2016, the Partnership recognized increases in partners' capital of $14 million.

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Bakken Equity Sale

In August 2016, ETP and Sunoco Logistics announced they have signed an agreement to sell 36.75% of the Bakken Pipeline project to MarEn Bakken Company LLC, an entity jointly owned by Enbridge Energy Partners, L.P. and Marathon Petroleum Corporation, for $2.00 billion in cash. The sale is expected to close in the third quarter of 2016, subject to certain closing conditions. ETP and Sunoco Logistics will receive $1.20 billion and $800 million in cash at closing, respectively, and will own a combined 38.25% of the Bakken Pipeline project.

Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by the Partnership subsequent to December 31, 2015:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 8, 2016	February 16, 2016	$1.0550
March 31, 2016	May 6, 2016	May 16, 2016	1.0550
June 30, 2016	August 8, 2016	August 15, 2016	1.0550

In July 2016, ETE agreed to relinquish incentive distributions over seven quarters, beginning with $75 million for the quarter ended June 30, 2016. ETE has also previously agreed to relinquish additional incentive distributions. In the aggregate, including relinquishment agreed to in July 2016, ETE has agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units.

	Total Year
2016 (remainder)	$249
2017	593
2018	105
2019	95

Sunoco Logistics Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2015:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 8, 2016	February 12, 2016	$0.4790
March 31, 2016	May 9, 2016	May 13, 2016	0.4890
June 30, 2016	August 8, 2016	August 12, 2016	0.5000

Accumulated Other Comprehensive Income (Loss)

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

	June 30, 2016	December 31, 2015
Available-for-sale securities	$ 5	$ —
Foreign currency translation adjustment	(5)	(4)
Actuarial gain related to pensions and other postretirement benefits	5	8
Investments in unconsolidated affiliates, net	(11)	—
Total AOCI, net of tax	$ (6)	$ 4

9. INCOME TAXES

For the three and six months ended June 30, 2016 and 2015, the Partnership’s income tax benefit primarily resulted from losses among the Partnership’s consolidated corporate subsidiaries. Also, for the three months ended June 30, 2015, the

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Partnership income tax expense was favorably impacted by $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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 purchasers. In June 2016, AmeriGas repurchased certain of its senior notes, which caused a reduction in the amount supported by ETP under the contingent residual support agreement. As of June 30, 2016, ETP continued to provide contingent, residual support of approximately $1 billion of borrowings.

ETP Retail Holdings Guarantee of Sunoco LP Notes

Retail Holdings has provided a guarantee of collection, but not of payment, to Sunoco LP with respect to (i) $800 million principal amount of 6.375% senior notes due 2023 issued by Sunoco LP, (ii) $800 million principal amount of 6.25% senior notes due 2021 issued by Sunoco LP and (iii) $2.035 billion aggregate principal for Sunoco LP's term loan due 2019.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas and New Mexico. We commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992. Under the ICA, tariff rates must be just and reasonable and not unduly discriminatory and pipelines may not confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

FERC Audit

In March 2016, the FERC commenced an audit of Trunkline for the period from January 1, 2013 to present to evaluate Trunkline's compliance with the requirements of its FERC gas tariff, the accounting regulations of the Uniform System of Accounts as prescribed by the FERC, and the FERC's annual reporting requirements. The audit is ongoing.

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 2058. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Rental expense[(1)]	$21	$54	$39	$106
Less: Sublease rental income	—	(4)	—	(12)
Rental expense, net	$21	$50	$39	$94

(1) Includes contingent rentals totaling $6 million and $10 million for the three and six months ended June 30, 2015, respectively.

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

Litigation and Contingencies

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

Mont Belvieu Incident

On June 26, 2016, a subsurface release of hydrocarbons and water, and a subsequent fire, occurred at Lone Star's South Terminal. All employees and contractors were accounted for, and there were no injuries. The cause of the fire and evaluation of possible damages is currently under investigation.

MTBE Litigation

Sunoco, Inc., 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 primarily assert 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 seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of June 30, 2016, Sunoco, Inc. is a defendant in five cases, including cases initiated by the States of New Jersey, Vermont, Pennsylvania, and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, Vermont, and Pennsylvania cases assert natural resource damage claims.

Fact discovery has concluded with respect to an initial set of 19 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. The initial set of 19 New Jersey trial sites are now pending before the United States District Judge for the District of New Jersey, the Hon. Freda L. Wolfson for the pre-trial and trial phases. Judge Wolfson then referred the case to United States Magistrate Judge for the District of New Jersey, the Hon. Lois H. Goodman. Judge Goodman conducted a status conference with all of the parties and inquired whether the parties will engage in a global mediation and instructed the parties to exchange possible mediator names. Sunoco informed Judge Goodman it is open to participating in global settlement discussions in a global mediation forum. The remaining portion of the New Jersey case remains in the MDL. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership's consolidated financial position.

Regency Merger Litigation

Following the January 26, 2015 announcement of the Regency Merger, purported Regency unitholders filed lawsuits in state and federal courts in Dallas and Delaware asserting claims relating to the Regency Merger. All Regency Merger-related lawsuits have been dismissed, although one lawsuit remains pending on appeal. On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the Court of Chancery of the State of Delaware. The lawsuit alleges that the Regency Merger breached the Regency partnership agreement because Regency's conflicts committee was not properly formed, and the

Regency Merger was not approved in good faith. Defendants filed a motion to dismiss, and on March 29, 2016, the Delaware court granted Defendants' motion and dismissed the lawsuit. On April 26, 2016, Dieckman filed his Notice of Appeal to the Supreme Court of Delaware.

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This appeal is styled Adrian Dieckman v. Regency GP LP, et al., No. 208, 2016, in the Supreme Court of the State of Delaware. Dieckman filed his Opening Brief on June 9, 2016, and Defendants' Answering Brief is currently due on July 29, 2016.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise approximately $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise has filed a notice of appeal with the Texas Court of Appeals, and briefing by Enterprise and ETP is complete. Oral argument was held on April 20, 2016. The Court of Appeals is taking the briefs under advisement. In accordance with GAAP, no amounts related to the original verdict or the July 29, 2014 final judgment will be recorded in our financial statements until the appeal process is completed.

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of June 30, 2016 and December 31, 2015, accruals of approximately $56 million and $40 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

No amounts have been recorded in our June 30, 2016 or December 31, 2015 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Attorney General of the Commonwealth of Massachusetts v. New England Gas Company.

On July 7, 2011, the Massachusetts Attorney General ("AG") filed a regulatory complaint with the Massachusetts Department of Public Utilities ("MDPU") against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling approximately $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, the Southern Union former Vice Chairman, President and Chief Operating Officer, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Panhandle (as successor to Southern Union) believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Panhandle will continue to assess its potential exposure for such cost recoveries as the matter progresses.

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Compliance Orders from the New Mexico Environmental Department

Regency received a Notice of Violation from the New Mexico Environmental Department on September 23, 2015 for allegations of violations of New Mexico air regulations related to Jal #3. The Partnership has accrued $250,000 related to the claims and will continue to assess its potential exposure to the allegations as the matter progresses.

Lone Star NGL Fractionators Notice of Enforcement

Lone Star NGL Fractionators received a Notice of Enforcement from the Texas Commission on Environmental Quality on August 28, 2015 for allegations of violations of Texas air regulations related to its Mont Belvieu Gas Plant. The Partnership has accrued $300,000 related to the claim. As of April 2016, the Agreed Order is in the approval process with the Texas Commission on Environmental Quality and includes a $21,000 penalty and a $21,000 Supplemental Environmental Project.

Environmental Matters

Our operations are subject to extensive federal, tribal, 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 investigatory, remedial and corrective action obligations, the issuance of injunctions in affected areas 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.
- Legacy sites related to Sunoco, Inc., that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of June 30, 2016, Sunoco, Inc. had been named as a PRP at approximately 49 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.’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. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	June 30, 2016	December 31, 2015
Current	$ 35	$ 41
Non-current	289	326
Total environmental liabilities	$ 324	$ 367

In 2013, we established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.
During the three months ended June 30, 2016 and 2015, Sunoco, Inc. recorded $8 million and $11 million, respectively, of expenditures related to environmental cleanup programs. During the six months ended June 30, 2016 and 2015, Sunoco, Inc. recorded $14 million and $18 million, respectively, of expenditures related to environmental cleanup programs.
On December 2, 2010, Sunoco, Inc. entered an Asset Sale and Purchase Agreement to sell the Toledo Refinery to Toledo Refining Company LLC ("TRC") wherein Sunoco, Inc. retained certain liabilities associated with the pre-Closing time period. On January 2, 2013, USEPA issued a Finding of Violation ("FOV") to TRC and, on September 30, 2013, EPA issued an NOV/FOV to TRC alleging Clean Air Act violations. To date, EPA has not issued an FOV or NOV/FOV to Sunoco, Inc. directly but some of EPA's claims relate to the time period that Sunoco, Inc. operated the refinery. Specifically, EPA has claimed that the refinery flares were not operated in a manner consistent with good air pollution control practice for minimizing emissions and/or in conformance with their design, and that Sunoco, Inc. submitted semi-annual compliance reports in 2010 and 2011 that failed to include all of the information required by the regulations. EPA has proposed penalties in excess of $200,000 to resolve the allegations and discussions continue between the parties. The timing or outcome of this matter cannot be reasonably determined at this time, however, we do not expect there to be a material impact to our results of operations, cash flows or financial position.
Our pipeline operations are subject to regulation by the U.S. Department of Transportation under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.
In January 2012, Sunoco Logistics experienced a release on its products pipeline in Wellington, Ohio. In connection with this release, the PHMSA issued a Corrective Action Order under which Sunoco Logistics is obligated to follow specific requirements in the investigation of the release and the repair and reactivation of the pipeline. Sunoco

Logistics also entered into an Order on Consent with the EPA regarding the environmental remediation of the release site. All requirements of the Order on Consent with the EPA have been fulfilled and the Order has been satisfied and closed. Sunoco Logistics has also received a "No Further Action" approval from the Ohio EPA for all soil and groundwater remediation requirements. In May 2016, Sunoco Logistics received a proposed penalty from the EPA and U.S. Department of Justice associated with this release, and continues to work with the involved parties to bring this matter to closure. The timing and outcome of this matter cannot be reasonably determined at this time. However, Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

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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 past costs for OSHA required activities, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances have not had a material adverse effect on our results of operations but there is no assurance that such costs will not be material in the future.

11. DERIVATIVE 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 use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. At hedge inception, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract. Changes in the spreads between the forward natural gas prices 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.

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. These contracts are not designated as hedges for accounting purposes.

We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes 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 NGL. These contracts are not designated as hedges for accounting purposes.

We use derivatives in our liquids transportation and services segment to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

Sunoco Logistics utilizes swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These contracts are not designated as hedges for accounting purposes.

We use futures and swaps to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales and transportation costs in our retail marketing segment. These contracts are not designated as hedges for accounting purposes.

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

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The following table details our outstanding commodity-related derivatives:

	June 30, 2016		December 31, 2015	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	5,825,000	2016-2017	(602,500)	2016-2017
Basis Swaps IFERC/NYMEX[(1)]	7,920,000	2016-2017	(31,240,000)	2016-2017
Power (Megawatt):				
Forwards	272,164	2016-2017	357,092	2016-2017
Futures	(320,257)	2016-2017	(109,791)	2016
Options – Puts	(424,000)	2016	260,534	2016
Options – Calls	696,000	2016	1,300,647	2016
Crude (Bbls):				
Futures	(222,000)	2016-2017	(591,000)	2016-2017
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(522,500)	2016-2017	(6,522,500)	2016-2017
Swing Swaps IFERC	34,465,000	2016-2017	71,340,000	2016-2017
Fixed Swaps/Futures	(3,835,000)	2016-2018	(14,380,000)	2016-2018
Forward Physical Contracts	3,838,458	2016-2017	21,922,484	2016-2017
Natural Gas Liquid (Bbls) – Forwards/Swaps	(10,443,400)	2016	(8,146,800)	2016-2018
Refined Products (Bbls) – Futures	(1,557,000)	2016-2017	(993,000)	2016-2017
Corn (Bushels) – Futures	—	—	1,185,000	2016
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(42,167,500)	2016-2017	(37,555,000)	2016
Fixed Swaps/Futures	(42,167,500)	2016-2017	(37,555,000)	2016
Hedged Item – Inventory	42,167,500	2016-2017	37,555,000	2016

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

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.

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

Term	Type[(1)]	Notional Amount Outstanding June 30, 2016	Notional Amount Outstanding December 31, 2015
July 2016[(2)(4)]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	$ —	$ 200
July 2017[(3)(4)]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	500	300
July 2018[(3)]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300
July 2019[(3)]	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	200

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

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

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

(4) ETP previously had outstanding forward starting interest rate swaps, which were scheduled to expire in July 2016, with a total notional value of $200 million. In June 2016, ETP extended the expiration of those swaps to July 2017.

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. The Partnership also uses industry standard commercial agreements which allow for the netting of 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, gas and electric utilities, midstream companies and independent power generators. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that 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.

The Partnership has maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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

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Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$—	$ 38	$(4)	$ (3)
	—	38	(4)	(3)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	138	353	(173)	(306)
Commodity derivatives	46	57	(45)	(41)
Interest rate derivatives	29	—	(358)	(171)
Embedded derivatives in ETP Preferred Units	—	—	(9)	(5)
	213	410	(585)	(523)
Total derivatives	$213	$ 448	$(589)	$ (526)

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

	Balance Sheet Location	Asset Derivatives		Liability Derivatives	
		June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015
Derivatives without offsetting agreements	Derivative assets (liabilities)	$29	$ —	$(367)	$ (176)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	46	57	(45)	(41)
Broker cleared derivative contracts	Other current assets	138	391	(177)	(309)
Total gross derivatives		213	448	(589)	(526)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(22)	(17)	22	17
Payments on margin deposit	Other current assets	(138)	(309)	138	309
Total net derivatives		$53	$ 122	$(429)	$ (200)

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

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$ —	$ —	$ —	$ 1
Total	$ —	$ —	$ —	$ 1

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$21	$ 11	$17	$ 8
Total		$21	$ 11	$17	$ 8

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$(7)	$(6)	$(16)	$(8)
Commodity derivatives – Non-trading	Cost of products sold	(48)	(40)	(43)	(48)
Interest rate derivatives	Gains (losses) on interest rate derivatives	(81)	127	(151)	50
Embedded derivatives	Other, net	(4)	2	(4)	4
Total		$(140)	$83	$(214)	$(2)

12. RELATED PARTY TRANSACTIONS

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Affiliated revenues	$133	$130	$207	$206

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

	June 30, 2016	December 31, 2015
Accounts receivable from related companies:		
ETE	$ 58	$ 110
Sunoco LP	185	3
PES	9	10
FGT	9	13
Lake Charles LNG	30	36
Trans-Pecos Pipeline, LLC	—	29
Comanche Trail Pipeline, LLC	9	22
Other	54	45
Total accounts receivable from related companies:	$ 354	$ 268
Accounts payable to related companies:		
Sunoco LP	$ 10	$ 5
FGT	1	1
Lake Charles LNG	2	3
Other	8	16
Total accounts payable to related companies:	$ 21	$ 25

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

	June 30, 2016	December 31, 2015
Long-term notes payable – related companies:		
Sunoco LP	$ 75	$ 233
Phillips 66	107	—
Long-term notes payable – related companies:	$ 182	$ 233

13. REPORTABLE SEGMENTS

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

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- liquids transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and

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•all other.

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

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our liquids 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, depletion, 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, and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership’s proportionate ownership.

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The following tables present financial information by segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$428	$486	$874	$1,027
Intersegment revenues	113	83	225	128
	541	569	1,099	1,155
Interstate transportation and storage:				
Revenues from external customers	229	239	483	510
Intersegment revenues	5	4	10	9
	234	243	493	519
Midstream:				
Revenues from external customers	690	767	1,217	1,516
Intersegment revenues	640	473	1,205	875
	1,330	1,240	2,422	2,391
Liquids transportation and services:				
Revenues from external customers	1,099	783	1,928	1,595
Intersegment revenues	11	45	101	68
	1,110	828	2,029	1,663
Investment in Sunoco Logistics:				
Revenues from external customers	2,250	3,120	3,979	5,646
Intersegment revenues	18	82	66	128
	2,268	3,202	4,045	5,774
Retail marketing:				
Revenues from external customers	—	5,557	—	10,339
Intersegment revenues	—	(20)	—	3
	—	5,537	—	10,342
All other:				
Revenues from external customers	593	588	1,289	1,233
Intersegment revenues	118	134	276	231
	711	722	1,565	1,464
Eliminations	(905)	(801)	(1,883)	(1,442)
Total revenues	$5,289	$11,540	$9,770	$21,866

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$149	$117	$328	$294
Interstate transportation and storage	278	285	570	586
Midstream	298	352	561	662
Liquids transportation and services	220	154	447	323
Investment in Sunoco Logistics	245	326	594	547
Retail marketing	68	140	125	269
All other	112	114	157	173
Total	1,370	1,488	2,782	2,854
Depreciation, depletion and amortization	(496)	(501)	(966)	(980)
Interest expense, net	(317)	(336)	(636)	(646)
Gains (losses) on interest rate derivatives	(81)	127	(151)	50
Non-cash unit-based compensation expense	(19)	(23)	(38)	(43)
Unrealized losses on commodity risk management activities	(18)	(42)	(81)	(119)
Inventory valuation adjustments	132	184	106	150
Losses on extinguishments of debt	—	(33)	—	(33)
Adjusted EBITDA related to unconsolidated affiliates	(252)	(215)	(471)	(361)
Equity in earnings of unconsolidated affiliates	119	117	195	174
Other, net	25	14	41	19
Income before income tax benefit	$463	$780	$781	$1,065

	June 30, 2016	December 31, 2015
Assets:		
Intrastate transportation and storage	$5,134	$ 4,882
Interstate transportation and storage	11,551	11,345
Midstream	17,604	17,111
Liquids transportation and services	8,977	7,235
Investment in Sunoco Logistics	16,780	15,423
Retail marketing	1,387	3,218
All other	4,608	5,959
Total assets	$66,041	$ 65,173

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

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; (ii) our Annual Report on Form 10-K for the year ended December 31, 2015 filed with the SEC on February 29, 2016; and (iii) our management's discussion and analysis of financial condition and results of operations included in our 2015 Form 10-K. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Part I – Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2015.

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

OVERVIEW

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

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger, CrossCountry, ETC MEP and ET Rover. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- Liquids operations, including NGL transportation, storage and fractionation services.
- Product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics.

RECENT DEVELOPMENTS

Sunoco Retail to Sunoco LP

In March 2016, ETP contributed to Sunoco LP its remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP paid $2.20 billion in cash, including a working capital adjustment, and issued 5.7 million Sunoco LP common units to Retail Holdings, a wholly-owned subsidiary of the Partnership. The transaction was effective January 1, 2016. In connection with this transaction, the Partnership deconsolidated the legacy Sunoco, Inc. retail business, including goodwill of $1.29 billion and intangible assets of $294 million. The results of Sunoco, LLC and the legacy Sunoco, Inc. retail business' operations have not been presented as discontinued operations and Sunoco, Inc.'s retail business assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements.

Bayou Bridge

In April 2016, Bayou Bridge Pipeline, LLC ("Bayou Bridge"), a joint venture among ETP, Sunoco Logistics and Phillips 66 Partners LP, began commercial operations on the 30-inch segment of the pipeline from Nederland, Texas to Lake Charles, Louisiana. ETP and Sunoco Logistics each hold a 30% interest in the entity and Sunoco Logistics is the operator of the system.

Bakken Financing

In August 2016, ETP, Sunoco Logistics and Phillips 66 announced the completion of the project-level financing of the Bakken Pipeline. The $2.50 billion facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects.

Bakken Equity Sale

In August 2016, ETP and Sunoco Logistics announced they have signed an agreement to sell 36.75% of the Bakken Pipeline project to MarEn Bakken Company LLC, an entity jointly owned by Enbridge Energy Partners, L.P. and Marathon Petroleum Corporation, for $2.00 billion in cash. The sale is expected to close in the third quarter of 2016, subject to certain closing conditions. ETP and Sunoco Logistics will receive $1.20 billion and $800 million in cash at closing, respectively, and will own a combined 38.25% of the Bakken Pipeline project.

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Results of Operations
Consolidated Results

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$149	$117	$32	$328	$294	$34
Interstate transportation and storage	278	285	(7)	570	586	(16)
Midstream	298	352	(54)	561	662	(101)
Liquids transportation and services	220	154	66	447	323	124
Investment in Sunoco Logistics	245	326	(81)	594	547	47
Retail marketing	68	140	(72)	125	269	(144)
All other	112	114	(2)	157	173	(16)
Total	1,370	1,488	(118)	2,782	2,854	(72)
Depreciation, depletion and amortization	(496)	(501)	5	(966)	(980)	14
Interest expense, net	(317)	(336)	19	(636)	(646)	10
Losses on extinguishments of debt	—	(33)	33	—	(33)	33
Gains (losses) on interest rate derivatives	(81)	127	(208)	(151)	50	(201)
Non-cash unit-based compensation expense	(19)	(23)	4	(38)	(43)	5
Unrealized losses on commodity risk management activities	(18)	(42)	24	(81)	(119)	38
Inventory valuation adjustments	132	184	(52)	106	150	(44)
Adjusted EBITDA related to unconsolidated affiliates	(252)	(215)	(37)	(471)	(361)	(110)
Equity in earnings of unconsolidated affiliates	119	117	2	195	174	21
Other, net	25	14	11	41	19	22
Income before income tax benefit	463	780	(317)	781	1,065	(284)
Income tax benefit	9	59	(50)	67	42	25
Net income	$472	$839	$(367)	$848	$1,107	$(259)

See the detailed discussion of Segment Adjusted EBITDA and Segment Operating Results.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased for the three and six months ended June 30, 2016 compared to the same periods last year primarily due to decreases of $74 million and $144 million, respectively, related to the deconsolidation of Sunoco, LLC and the legacy Sunoco, Inc. retail business, partially offset by increases from assets recently placed in service.

Gains (Losses) on Interest Rate Derivatives. Losses on interest rate derivatives during the three and six months ended June 30, 2016 were primarily attributable to the impact on our forward starting swap locks from the downward shift in the forward LIBOR curve. The gains reflected for the three and six months ended June 30, 2015 resulted from increases in forward interest rates, which caused our forward-starting swaps to increase in value.

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

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco Logistics’ crude oil, NGLs and refined products inventories as a result of commodity price changes during the respective periods. The three and six months ended June 30, 2015 also reflected $57 million and $64 million related to our retail marketing operations prior to our deconsolidation of these operations.

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

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

Income Tax Benefit. For the three and six months ended June 30, 2016 and 2015, the Partnership’s income tax benefit primarily resulted from losses among the Partnership’s consolidated corporate subsidiaries. Also, for the three months ended June 30, 2015, the Partnership income tax expense was favorably impacted by $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$28	$29	$ (1)	$49	$48	$ 1
FEP	12	13	(1)	26	27	(1)
PES	7	47	(40)	1	38	(37)
MEP	11	11	—	22	23	(1)
HPC	7	6	1	15	15	—
AmeriGas	19	(2)	21	17	4	13
Sunoco LP	23	—	23	38	—	38
Other	12	13	(1)	27	19	8
Total equity in earnings of unconsolidated affiliates	$119	$117	$ 2	$195	$174	$ 21
Adjusted EBITDA related to unconsolidated affiliates[(1)]:						
Citrus	$87	$85	$ 2	$161	$154	$ 7
FEP	18	18	—	37	37	—
PES	17	54	(37)	21	56	(35)
MEP	23	24	(1)	47	48	(1)
HPC	15	15	—	30	30	—
Sunoco LP	68	—	68	125	—	125
Other	24	19	5	50	36	14
Total Adjusted EBITDA related to unconsolidated affiliates	$252	$215	$ 37	$471	$361	$ 110
Distributions received from unconsolidated affiliates:						
Citrus	$27	$47	$ (20)	$62	$80	$ (18)
FEP	13	16	(3)	30	32	(2)
AmeriGas	3	3	—	6	6	—
PES	—	19	(19)	—	21	(21)
MEP	18	20	(2)	39	40	(1)
HPC	13	14	(1)	25	27	(2)
Sunoco LP	36	—	36	66	—	66
Other	10	9	1	27	20	7
Total distributions received from unconsolidated affiliates	$120	$128	$ (8)	$255	$226	$ 29

(1) These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates and are based on our equity in earnings or losses of our unconsolidated affiliates adjusted for our proportionate share of the unconsolidated affiliates' interest, depreciation, amortization, non-cash items and taxes.

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Segment Operating Results

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

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

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

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Natural gas transported (MMBtu/d)	7,861,264	8,666,363	(805,099)	7,925,818	8,739,721	(813,903)
Revenues	$541	$ 569	$ (28)	$1,099	$ 1,155	$ (56)
Cost of products sold	353	383	(30)	746	799	(53)
Gross margin	188	186	2	353	356	(3)
Unrealized (gains) losses on commodity risk management activities	(7)	(34)	27	31	1	30
Operating expenses, excluding non-cash compensation expense	(41)	(42)	1	(74)	(78)	4
Selling, general and administrative expenses, excluding non-cash compensation expense	(6)	(8)	2	(12)	(15)	3
Adjusted EBITDA related to unconsolidated affiliates	15	15	—	30	30	—
Segment Adjusted EBITDA	$149	$ 117	$ 32	$328	$ 294	$ 34

Volumes. For the three and six months ended June 30, 2016 compared to the same periods last year, transported volumes decreased primarily due to lower production volumes, primarily in the Barnett Shale region, partially offset by increased volumes related to significant new long-term transportation contracts.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Transportation fees	$125	$127	$ (2)	$259	$255	$ 4
Natural gas sales and other	32	27	5	55	51	4
Retained fuel revenues	10	15	(5)	20	30	(10)
Storage margin, including fees	21	17	4	19	20	(1)
Total gross margin	$188	$186	$ 2	$353	$356	$ (3)

Segment Adjusted EBITDA. For the three months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- a decrease of $2 million in transportation fees due to lower throughput volumes;
- an increase of $2 million in natural gas sales (excluding changes in unrealized gains of $3 million) and other primarily due to higher realized gains from the buying and selling of gas along our system, as well as lower fuel losses;
- a decrease of $2 million from the sale of retained fuel (excluding changes in unrealized losses of $3 million) primarily due to significantly lower market prices. The average spot price at the Houston Ship Channel location decreased 23% for the three months ended June 30, 2016 compared to the same period last year;
- an increase of $30 million in storage margin (excluding net changes in unrealized amounts of $26 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below;
- a decrease of $1 million in operating expenses due to lower costs for gas used to run compressors on our pipelines as a result of lower market prices; and
- a decrease of $2 million in general and administrative expenses due to lower legal fees, as well as lower allocated overhead costs due to shared services cost savings.

Segment Adjusted EBITDA. For the six months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $4 million in transportation fees despite lower throughput volumes, due to fees from renegotiated and newly initiated fixed fee contracts primarily on our Houston Pipeline system;
- an increase of $9 million in natural gas sales (excluding changes in unrealized loss of $5 million) primarily due to higher realized gains from the buying and selling gas along our system, as well as lower fuel losses;
- a decrease of $8 million from the sale of retained fuel (excluding changes in unrealized losses of $2 million) primarily due to significantly lower market prices. The average spot price at the Houston Ship Channel location decreased 27% for the six months ended June 30, 2016 compared to the same period last year;
- an increase of $23 million in storage margin (excluding net changes in unrealized amounts of $24 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below;
- a decrease of $4 million in operating expenses due to lower costs for electricity used to run compressors on our pipelines as a result of lower market prices for natural gas; and
- a decrease of $3 million in general and administrative expenses due to lower legal fees, as well as lower allocated overhead costs due to shared services cost savings.

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Storage margin was comprised of the following:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Withdrawals from storage natural gas inventory (MMBtu)	662,500	—	662,500	21,657,500	15,782,500	5,875,000
Realized margin on natural gas inventory transactions	$8	$(23)	$ 31	$36	$ 12	$ 24
Fair value inventory adjustments	39	11	28	56	23	33
Unrealized gains (losses) on derivatives	(33)	22	(55)	(86)	(29)	(57)
Margin recognized on natural gas inventory, including related derivatives	14	10	4	6	6	—
Revenues from fee-based storage	7	7	—	13	14	(1)
Total storage margin	$21	$17	$ 4	$19	$ 20	$ (1)

The changes in storage margin were primarily driven by the timing of the movement of market prices during both periods.

Interstate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Natural gas transported (MMBtu/d)	5,363,658	5,873,424	(509,766)	5,599,352	6,331,536	(732,184)
Natural gas sold (MMBtu/d)	21,539	14,827	6,712	19,358	15,736	3,622
Revenues	$234	$ 243	$ (9)	$493	$ 519	$ (26)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(75)	(71)	(4)	(147)	(143)	(4)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(11)	(14)	3	(23)	(29)	6
Adjusted EBITDA related to unconsolidated affiliates	128	127	1	245	239	6
Other	2	—	2	2	—	2
Segment Adjusted EBITDA	$278	$ 285	$ (7)	$570	$ 586	$ (16)

Volumes. For the three and six months ended June 30, 2016 compared to the same periods last year, transported volumes decreased 343,629 MMBtu/d and 565,386 MMBtu/d, respectively, on the Trunkline pipeline due to the transfer of one of the pipelines at Trunkline which was repurposed from natural gas service to crude oil service, 96,758 MMBtu/d and 60,082 MMBtu/d, respectively, on the Sea Robin pipeline due to reduced supply as a result of producer system maintenance and overall lower production, and 84,390 MMBtu/d and 89,054 MMBtu/d, respectively, on the Tiger pipeline due to lower contract utilization due to market conditions.

Segment Adjusted EBITDA. For the three months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net effects of the following:

- a decrease of approximately $9 million in revenues due to contract restructuring on the Tiger pipeline, $4 million due to the transfer of one of the Trunkline pipelines which was repurposed from natural gas service to crude oil service, and $3 million due to the expiration of a transportation rate schedule on the Transwestern pipeline. These decreases were partially offset by higher revenues of $7 million from gas parking services; and
- an increase of $4 million in operating expenses primarily due to higher system gas balancing expenses; partially offset by

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- a decrease of $3 million in selling, general and administrative expenses primarily due to lower employee related expenses and lower allocations; and
- an increase of $2 million in other items due to income associated with a reimbursable project.

Segment Adjusted EBITDA. For the six months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net effects of the following:

- a decrease of approximately $14 million in revenues due to the transfer of one of the Trunkline pipelines which was repurposed from natural gas service to crude oil service, $11 million due to the expiration of a transportation rate schedule on the Transwestern pipeline, $9 million as a result of contract restructuring on the Tiger pipeline, and $4 million on the Sea Robin pipeline due to reduced gas supply as indicated above. These decreases were partially offset by $9 million from increased sales of capacity on the Transwestern pipeline and $6 million from gas parking services on the Panhandle and Trunkline pipelines; and
- an increase of $4 million in operating expenses primarily due to higher ad valorem taxes as a result of true up of taxes in 2015 associated with lower valuations; partially offset by
- a decrease of $6 million in selling, general and administrative expenses primarily due to a reduction in allocations and lower employee related expenses;
- an increase of $6 million in adjusted EBITDA related to unconsolidated affiliates due to higher equity from Citrus as a result of higher revenues from one additional operating day and Phase VIII related revenues and lower maintenance related expenses; and
- an increase of $2 million in other items due to income associated with a reimbursable project.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Gathered volumes (MMBtu/d)	10,037,648	9,964,237	73,411	9,944,376	9,740,653	203,723
NGLs produced (Bbls/d)	468,732	399,662	69,070	449,853	383,611	66,242
Equity NGLs (Bbls/d)	31,638	30,160	1,478	30,585	29,130	1,455
Revenues	$ 1,330	$ 1,240	$ 90	$ 2,422	$ 2,391	$ 31
Cost of products sold	870	796	74	1,548	1,508	40
Gross margin	460	444	16	874	883	(9)
Unrealized losses on commodity risk management activities	—	71	(71)	—	82	(82)
Operating expenses, excluding non-cash compensation expense	(155)	(147)	(8)	(300)	(285)	(15)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(24)	11	(25)	(27)	2
Adjusted EBITDA related to unconsolidated affiliates	6	7	(1)	12	8	4
Other	—	1	(1)	—	1	(1)
Segment Adjusted EBITDA	$ 298	$ 352	$ (54)	$ 561	$ 662	$ (101)

Volumes. Gathered volumes and NGLs produced increased during the three and six months ended June 30, 2016 compared to the same periods last year primarily due to increased gathering and processing capacities in the Permian Basin, Eagle Ford and Cotton Valley regions, partially offset by declines in the Mid-Continent/Panhandle and North Texas regions. In addition, volumes also increased for the six months ended June 30, 2016 due to the King Ranch acquisition in the second quarter of 2015.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Gathering and processing fee-based revenues	$396	$384	$ 12	$770	$754	$ 16
Non fee-based contracts and processing	64	60	4	104	129	(25)
Total gross margin	$460	$444	$ 16	$874	$883	$ (9)

Segment Adjusted EBITDA. For the three months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net effects of the following:

- a decrease of $5 million in non-fee based margins due to lower natural gas prices and a $5 million decrease in non-fee based margins due to lower crude oil and NGL prices;
- a decrease in gross margin of $63 million due to lower benefit from settled derivatives used to hedge commodity margins; and
- an increase in operating expenses of $8 million primarily due to assets that are recently placed in service in the Permian and Eagle Ford regions; offset by
- increases of $10 million in fee-based revenues and $5 million in non-fee based margins due to increased production and increased capacity from assets placed in service in the Eagle Ford, Permian Basin and Cotton Valley regions, partially offset by volume declines in the North Texas and Mid-Continent/Panhandle regions; and
- a decrease in general and administrative expenses of $11 million primarily due to a lower allocation of employee-related expenses to the midstream segment.

Segment Adjusted EBITDA. For the six months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net effects of the following:

- a decrease of $14 million in non-fee based margins due to lower natural gas prices and a $28 million decrease in non-fee based margins due to lower crude oil and NGL prices;
- a decrease in gross margin of $85 million due to lower benefit from settled derivatives used to hedge commodity margins; and
- an increase in operating expenses of $15 million primarily due to the King Ranch acquisition in the second quarter of 2015 and assets recently placed in service in the Permian and Eagle Ford regions; offset by
- increases of $15 million in fee-based revenues and $20 million in non-fee based margins due to increased production and increased capacity from assets placed in service in the Eagle Ford, Permian Basin and Cotton Valley regions, partially offset by volume declines in the North Texas and Mid-Continent/Panhandle regions;
- a decrease in general and administrative expenses of $2 million primarily due to a lower allocation of employee-related expenses to the midstream segment; and
- an increase of $4 million in adjusted EBITDA related to unconsolidated affiliates due to increased volumes through our unconsolidated joint ventures.

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Liquids Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Liquids transportation volumes (Bbls/d)	607,656	455,739	151,917	552,338	432,252	120,086
NGL fractionation volumes (Bbls/d)	345,182	246,348	98,834	355,957	232,414	123,543
Revenues	$1,110	$ 828	$ 282	$2,029	$1,663	$ 366
Cost of products sold	850	629	221	1,511	1,267	244
Gross margin	260	199	61	518	396	122
Unrealized (gains) losses on commodity risk management activities	6	(5)	11	15	4	11
Operating expenses, excluding non-cash compensation expense	(41)	(39)	(2)	(78)	(74)	(4)
Selling, general and administrative expenses, excluding non-cash compensation expense	(5)	(4)	(1)	(10)	(8)	(2)
Adjusted EBITDA related to unconsolidated affiliates	—	3	(3)	2	5	(3)
Segment Adjusted EBITDA	$220	$ 154	$ 66	$447	$323	$ 124

Volumes. For the three and six months ended June 30, 2016 compared to the same periods last year, NGL transportation volumes increased in all major producing regions, including the Permian, North Texas, Southeast Texas, Eagle Ford, and Louisiana. Additionally, our crude transportation pipeline in the Eagle Ford region transported approximately 45,000 Bbls/d for the three and six months ended June 30, 2016 compared to 36,000 Bbls/d and 37,000 Bbls/d for the three and six months ended June 30, 2015, respectively. Our crude pipeline, originating in Nederland and delivering into Lake Charles, also began transporting volumes in April 2016, and transported approximately 57,000 Bbls/d during the three months ended June 30, 2016.

Average daily fractionated volumes increased for the three and six months ended June 30, 2016 compared to the same periods last year due to the ramp-up of our third 100,000 Bbls/d fractionator at Mont Belvieu, Texas, which was commissioned in late December 2015, as well as increased producer volumes, as mentioned above.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Transportation margin	$123	$96	$ 27	$231	$180	$ 51
Processing and fractionation margin	93	76	17	193	141	52
Storage margin	49	39	10	98	83	15
Other margin	(5)	(12)	7	(4)	(8)	4
Total gross margin	$260	$199	$ 61	$518	$396	$ 122

Segment Adjusted EBITDA. For the three and six months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our liquids transportation and services segment increased due to the net impacts of the following:

- increases in storage margin of $10 million and $15 million, respectively, partially due to an increase in demand for leased storage capacity as a result of favorable market conditions, which increased fee-based storage revenues by $3 million and $5 million, respectively. The remainder of the storage margin increases were primarily due to increases in throughput fees, as shuttle volumes increased for the three and six months ended June 30, 2016 by 36% and 33%, respectively;
- increases in transportation fees of $27 million and $51 million, respectively, due to significantly higher volumes transported out of all of our producing regions and higher average rates. The increase in average rates was primarily due to a higher proportion of the volumes originating from West Texas where transport rates are higher. Higher

volumes from the Permian region resulted in increases in margin of $18 million and $38 million for the three and six months ended June 30, 2016, respectively;

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- increases of $15 million and $54 million, respectively, in processing and fractionation margin (excluding changes in unrealized gains of $2 million for the three month period and unrealized losses of $2 million for the six month period) primarily due to the ramp-up of our third 100,000 Bbls/d fractionator at Mont Belvieu, Texas, along with higher producer volumes, primarily from West Texas. Additionally, the six months ended June 30, 2016 also reflect an additional $17 million increase from the commissioning of the Mariner South LPG export project during February 2015. Margin associated with our off-gas fractionator in Geismar, Louisiana decreased by $2 million and $5 million for the three and six months ended June 30, 2016, respectively, as NGL and olefin market prices decreased significantly for the comparable periods; and
- increases of $20 million and $12 million, respectively, in other margin (excluding increases in unrealized losses of $13 million and $8 million, respectively) primarily due to more favorable market conditions; offset by
- increases in operating expenses of $2 million and $4 million, respectively, primarily due to increased costs associated with our third fractionator at Mont Belvieu; and
- increases in general and administrative expenses of $1 million and $2 million, respectively, due to lower capitalized overhead as a result of reduced capital spending.

Investment in Sunoco Logistics

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Revenues	$2,268	$3,202	$(934)	$4,045	$5,774	$(1,729)
Cost of products sold	1,859	2,737	(878)	3,298	5,096	(1,798)
Gross margin	409	465	(56)	747	678	69
Unrealized losses on commodity risk management activities	4	8	(4)	17	23	(6)
Operating expenses, excluding non-cash compensation expense	(31)	(37)	6	(52)	(76)	24
Selling, general and administrative expenses, excluding non-cash compensation expense	(24)	(23)	(1)	(47)	(45)	(2)
Inventory valuation adjustments	(132)	(100)	(32)	(106)	(59)	(47)
Adjusted EBITDA related to unconsolidated affiliates	19	13	6	35	26	9
Segment Adjusted EBITDA	$245	$326	$(81)	$594	$547	$47

Segment Adjusted EBITDA. For the three months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics decreased due to the following:

- a decrease of $49 million from Sunoco Logistics' crude oil operations. The decrease was largely attributable to lower operating results from Sunoco Logistics' crude oil acquisition and marketing activities of $112 million, which includes the reversal of approximately $60 million of positive LIFO inventory accounting that was reflected in the first quarter of 2016 related to contango market opportunities. The acquisition and marketing results, which include transportation and storage fees related to Sunoco Logistics' crude oil pipelines and terminal facilities, were also impacted by lower volumes and significantly lower crude oil differentials. This decrease was partially offset by improved results from Sunoco Logistics' crude oil pipelines of $50 million which benefited from the Permian Express 2 pipeline that commenced operations in July 2015. Higher results from Sunoco Logistics' crude oil terminals of $11 million largely related to Sunoco Logistics' Nederland facility and improved contributions from joint venture interests of $3 million also contributed to the offset; and
- a decrease of $51 million from Sunoco Logistics' NGLs operations, primarily due to lower results from Sunoco Logistics' NGLs acquisition and marketing activities of $60 million, which includes the absence of approximately $25 million of positive LIFO inventory accounting reflected in the second quarter of 2015. Lower volumes and margins attributable to acquisition and marketing activities also contributed to the decrease. These factors were partially offset by increased volumes and fees from Sunoco Logistics' Mariner NGLs projects of $10 million, which includes Sunoco Logistics' NGLs pipelines and Marcus Hook facility; offset by
- an increase of $19 million from Sunoco Logistics' refined products operations, primarily due to improved operating results from Sunoco Logistics' refined products pipelines of $9 million, which benefited from higher volumes on

Sunoco Logistics' Allegheny Access pipeline, and higher results from Sunoco Logistics' refined products terminals of $4 million. Higher

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contributions from joint venture interests of $3 million and Sunoco Logistics' refined products acquisition and marketing activities of $2 million also contributed to the increase.

For the six months ended June 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $15 million from Sunoco Logistics' crude oil operations. The increase was due to improved results from Sunoco Logistics' crude oil pipelines of $95 million which benefited from the Permian Express 2 pipeline that commenced operations in July 2015. Higher results from Sunoco Logistics' crude oil terminals of $19 million largely related to Sunoco Logistics' Nederland facility and improved contributions from joint venture interests of $5 million also contributed to the increase. These positive factors were largely offset by a decrease in operating results from Sunoco Logistics' crude oil acquisition and marketing activities of $102 million, which includes transportation and storage fees related to Sunoco Logistics' crude oil pipelines and terminal facilities, due to decreased volumes and significantly lower crude oil differentials; and
- an increase of $37 million from Sunoco Logistics' refined products operations, primarily due to increased operating results from Sunoco Logistics' refined products pipelines of $18 million, which benefited from higher volumes on Sunoco Logistics' Allegheny Access pipeline, and improved earnings from Sunoco Logistics' refined products acquisition and marketing activities of $10 million. Higher earnings attributable to Sunoco Logistics' refined products terminals of $5 million and improved contributions from joint venture interests of $4 million also impacted the improvement; offset by
- a decrease of $5 million from Sunoco Logistics' NGLs operations, primarily due to lower volumes and margins from Sunoco Logistics' NGLs acquisition and marketing activities of $53 million. These factors were largely offset by increased volumes and fees from Sunoco Logistics' Mariner NGLs projects of $48 million, which includes Sunoco Logistics' NGLs pipelines and Nederland and Marcus Hook facilities.

Retail Marketing

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Revenues	$—	$5,537	$(5,537)	$—	$10,342	$(10,342)
Cost of products sold	—	5,003	(5,003)	—	9,370	(9,370)
Gross margin	—	534	(534)	—	972	(972)
Unrealized losses on commodity risk management activities	—	1	(1)	—	3	(3)
Operating expenses, excluding non-cash compensation expense	—	(281)	281	—	(552)	552
Selling, general and administrative expenses, excluding non-cash compensation expense	—	(57)	57	—	(91)	91
Inventory valuation adjustments	—	(57)	57	—	(64)	64
Adjusted EBITDA related to unconsolidated affiliates	68	—	68	125	1	124
Segment Adjusted EBITDA	$68	$140	$(72)	$125	$269	$(144)

Due to the transfer of the general partnership interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016, the Partnership's retail marketing segment has been deconsolidated, and the segment results now reflect an equity method investment in limited partnership units of Sunoco LP. As of June 30, 2016, the Partnership owns 43.5 million Sunoco LP common units, representing 45.6% of Sunoco LP's total outstanding common units.

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All Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Revenues	$711	$722	$ (11)	$1,565	$1,464	$ 101
Cost of products sold	625	617	8	1,386	1,252	134
Gross margin	86	105	(19)	179	212	(33)
Unrealized losses on commodity risk management activities	15	1	14	18	6	12
Operating expenses, excluding non-cash compensation expense	(16)	(23)	7	(37)	(46)	9
Selling, general and administrative expenses, excluding non-cash compensation expense	(19)	(30)	11	(46)	(79)	33
Adjusted EBITDA related to unconsolidated affiliates	17	53	(36)	21	56	(35)
Other	24	24	—	48	48	—
Eliminations	5	(16)	21	(26)	(24)	(2)
Segment Adjusted EBITDA	$112	$114	$ (2)	$157	$173	$ (16)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities.

For the three and six months ended June 30, 2016 compared to the same periods last year, Segment Adjusted EBITDA related to our all other segment decreased due to lower earnings from our investment in PES, a decrease in revenue-generating horsepower and lower project revenue from our compression operations, partially offset by a favorable variance from lower transaction-related expenses in 2016 and higher selling, general and administrative expenses in 2015.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

We currently expect the following capital expenditures in 2016 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage[2]	$30	$40	$20	$25
Interstate transportation and storage[2][3]	210	250	105	115
Midstream	1,225	1,275	125	135
Liquids transportation and services				
NGL	975	1,000	20	25
Crude[2][3]	300	325	—	—
All other (including eliminations)	90	100	40	45
Total direct capital expenditures	$2,830	$2,990	$310	$345

(1) Direct capital expenditures exclude those funded by our publicly traded subsidiary.

(2) Net of amounts forecasted to be financed at the asset level with non-recourse debt of approximately $1.16 billion.

(3) Includes capital expenditures related to our proportionate ownership of the Bakken, Rover and Bayou Bridge pipeline projects.

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

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional common units, dropdown proceeds or the monetization of non-core assets or a combination thereof.

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in “Results of Operations” above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Six months ended June 30, 2016 compared to six months ended June 30, 2015. Cash provided by operating activities during 2016 was $1.43 billion compared to $1.13 billion for 2015 and net income was $848 million and $1.11 billion for 2016 and 2015, respectively. The difference between net income and cash provided by operating activities for the six months ended June 30, 2016 primarily consisted of net changes in operating assets and liabilities of $96 million and non-cash items totaling $488 million.

The non-cash activity in 2016 and 2015 consisted primarily of depreciation, depletion and amortization of $966 million and $980 million, respectively, non-cash compensation expense of $38 million and $43 million, respectively, and equity in earnings

of unconsolidated affiliates of $195 million and $174 million, respectively. Non-cash activity in 2016 also included deferred income taxes of $79 million and inventory valuation adjustments of $106 million.
Cash paid for interest, net of interest capitalized, was $669 million and $709 million for the six months ended June 30, 2016 and 2015, respectively.
Capitalized interest was $111 million and $69 million for the six months ended June 30, 2016 and 2015, respectively.
Investing Activities
Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash distributions from our joint ventures, and cash proceeds from sales or contributions of assets or businesses. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.
Six months ended June 30, 2016 compared to six months ended June 30, 2015. Cash provided by investing activities during 2016 was $1.23 billion compared to cash used in investing activities of $3.66 billion for 2015. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2016 were $3.45 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2015 of $4.13 billion. Additional detail related to our capital expenditures is provided in the table below. During 2016, we received $2.20 billion in cash related to the contribution of our Sunoco, Inc. retail business to Sunoco LP. During 2015, we received $980 million in cash related to the Bakken Pipeline Transaction and paid $604 million in cash for all other acquisitions.
The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the six months ended June 30, 2016:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Direct[1]:			
Intrastate transportation and storage	$25	$ 6	$31
Interstate transportation and storage[2]	87	26	113
Midstream	586	49	635
Liquids transportation and services[2]	1,342	9	1,351
All other (including eliminations)	54	20	74
Total direct capital expenditures	2,094	110	2,204
Indirect[1]:			
Investment in Sunoco Logistics	821	27	848
Total capital expenditures	$2,915	$ 137	$3,052

(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiary; all other capital expenditures are reflected as direct capital expenditures.

(2) Includes capital expenditures related to the Bakken, Rover and Bayou Bridge pipeline projects, which includes $277 million related to Sunoco Logistics' proportionate ownership in the Bakken and Bayou Bridge pipeline projects.

Financing Activities
Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.
Six months ended June 30, 2016 compared to six months ended June 30, 2015. Cash used in financing activities during 2016 was $342 million compared to cashed provided by financing activities of $3.48 billion for 2015. In 2016 and 2015, we received net proceeds from Common Unit offerings of $408 million and $724 million, respectively. In 2016 and 2015, our subsidiaries received $667 million and $1.01 billion, respectively, in net proceeds from the issuance of common units. During 2016, we had a net increase in our debt level of $444 million compared to a net

increase of $3.11 billion for 2015. We have paid distributions of $1.81 billion to our partners in 2016 compared to $1.38 billion in 2015. We have also paid distributions of $209 million to noncontrolling interests in 2016 compared to $165 million in 2015. In addition, we have received capital contributions of $161 million in cash from noncontrolling interests in 2016 compared to $398 million in 2015.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 2016	December 31, 2015
ETP Senior Notes	$19,439	$ 19,439
Transwestern Senior Notes	782	782
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	465	465
Sunoco Logistics Senior Notes	4,800	4,975
Revolving credit facilities:		
ETP $3.75 billion Revolving Credit Facility due November 2019	1,128	1,362
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020 [(1)]	1,263	562
Other long-term debt	31	32
Unamortized premiums, net of discounts and fair value adjustments	137	158
Deferred debt issuance costs	(173)	(181)
Total debt	28,957	28,679
Less: Current maturities of long-term debt	1,007	126
Long-term debt, less current maturities	$27,950	$ 28,553

(1) Includes $106 million of commercial paper product outstanding at June 30, 2016.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $3.75 billion and expires in November 2019. The indebtedness under the ETP Credit Facility is unsecured, is not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our current and future unsecured debt. As of June 30, 2016, the ETP Credit Facility had $1.13 billion of outstanding borrowings.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $2.50 billion unsecured revolving credit agreement (the “Sunoco Logistics Credit Facility”), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $3.25 billion under certain conditions. As of June 30, 2016, the Sunoco Logistics Credit Facility had $1.26 billion of outstanding borrowings.

Sunoco Logistics Senior Notes

Sunoco Logistics had $175 million of 6.125% senior notes which matured and were repaid in May 2016, using borrowings under the $2.50 billion Sunoco Logistics Credit Facility.

In July 2016, Sunoco Logistics issued $550 million aggregate principal amount of 3.90% senior notes due in July 2026. The net proceeds from this offering were used to repay outstanding credit facility borrowings and for general partnership purposes.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of June 30, 2016.

CASH DISTRIBUTIONS

Cash Distributions Paid by ETP

We expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders. Under our Partnership Agreement, we will distribute to our partners within 45 days after

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

Following are distributions declared and/or paid by us subsequent to December 31, 2015:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 8, 2016	February 16, 2016	$1.0550
March 31, 2016	May 6, 2016	May 16, 2016	1.0550
June 30, 2016	August 8, 2016	August 15, 2016	1.0550

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

	Six Months Ended June 30,	
	2016	2015
Common Units held by public	$1,053	$950
Common Units held by ETE	5	48
Class H Units held by ETE	171	118
General Partner interest held by ETE	16	15
Incentive distributions held by ETE	666	617
IDR relinquishments net of Class I Unit distributions	(144)	(55)
Total distributions declared to the partners of ETP	$1,767	$1,693

In July 2016, ETE agreed to relinquish incentive distributions over seven quarters, beginning with $75 million for the quarter ended June 30, 2016. ETE has also previously agreed to relinquish additional incentive distributions. In the aggregate, including relinquishment agreed to in July 2016, ETE has agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units.

Year	Total
2016 (remainder)	$249
2017	593
2018	105
2019	95

Cash Distributions Paid by Sunoco Logistics

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

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2015:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 8, 2016	February 12, 2016	$0.4790
March 31, 2016	May 9, 2016	May 13, 2016	0.4890
June 30, 2016	August 8, 2016	August 12, 2016	0.5000

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

	Six Months Ended June 30,	
	2016	2015
Limited Partners:		
Common units held by public	$223	$157
Common units held by ETP	66	57
General Partner interest held by ETP	7	6
Incentive distributions held by ETP	183	125
Total distributions declared	$479	$345

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2015, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed for the year ended December 31, 2015. Since December 31, 2015, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power, barrels for natural gas liquids, crude and refined products and bushels for corn. Dollar amounts are presented in millions.

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	June 30, 2016			December 31, 2015		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	5,825,000	$ 1	$ 2	(602,500)	$ (1)	$ —
Basis Swaps IFERC/NYMEX[1]	7,920,000	(3)	1	(31,240,000)	(1)	—
Power (Megawatt):						
Forwards	272,164	2	—	357,092	—	2
Futures	(320,257)	(1)	1	(109,791)	2	—
Options – Puts	(424,000)	—	—	260,534	—	—
Options – Calls	696,000	3	5	1,300,647	—	3
Crude (Bbls):						
Futures	(222,000)	(2)	4	(591,000)	4	3
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(522,500)	1	—	(6,522,500)	—	—
Swing Swaps IFERC	34,465,000	—	—	71,340,000	(1)	—
Fixed Swaps/Futures	(3,835,000)	1	1	(14,380,000)	(1)	5
Forward Physical Contracts	3,838,458	2	1	21,922,484	4	5
Natural Gas Liquid (Bbls) – Forwards/Swaps	(10,443,400)	(12)	43	(8,146,800)	10	13
Refined Products (Bbls) – Futures	(1,557,000)	(8)	1	(993,000)	9	5
Corn (Bushels) – Futures	—	—	—	1,185,000	—	1
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(42,167,500)	3	1	(37,555,000)	—	—
Fixed Swaps/Futures	(42,167,500)	(25)	14	(37,555,000)	73	9

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

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

Interest Rate Risk

As of June 30, 2016, we had $4.64 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $46 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

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

Term	Type[1]	Notional Amount Outstanding June 30, 2016	Notional Amount Outstanding December 31, 2015
July 2016[2][4]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	$ —	$ 200
July 2017[3][4]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	500	300
July 2018[3]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300
July 2019[3]	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	200

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

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

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

(4) ETP previously had outstanding forward starting interest rate swaps, which were scheduled to expire in July 2016, with a total notional value of $200 million. In June 2016, ETP extended the expiration of those swaps to July 2017.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $251 million as of June 30, 2016. For the $1.50 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $43 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of senior management, including the Chief Executive Officer (“Principal Executive Officer”) and the Chief Financial Officer (“Principal Financial Officer”) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of June 30, 2016 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II – OTHER INFORMATION
ITEM 1. LEGAL PROCEEDINGS
For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2015 and Note 10 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2016.
ITEM 1A. RISK FACTORS
There have been no material changes from the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2015. The following risk factor, which was previously included in our Form 10-K, has been included herein along with additional quantitative information with respect to the Partnership’s revenues, in order to supplement the disclosures previously provided in the Form 10-K.
The profitability of certain activities in our natural gas gathering, processing, transportation and storage operations are largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs.
For a portion of the natural gas gathered on our systems, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices.
We also enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers.
Under percent-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements, our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our revenues and results of operations.
Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.
When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. If recoveries are less than those guaranteed to the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole.
We also receive fees and retain gas in kind from our natural gas transportation and storage customers. Our fuel retention fees and the value of gas that we retain in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease our fuel retention fees and the value of retained gas.
In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.
For our midstream segment, we generally analyze gross margin based on fee-based margin (which includes revenues from processing fee arrangements) and non fee-based margin (which includes gross margin earned on percent-of-proceeds and keep-whole arrangements). For the six months ended June 30, 2016 and 2015, gross margin from our midstream segment totaled $874 million and $883 million, respectively, of which fee-based revenues constituted 88% and 85%, respectively, and non fee-based margin constituted 12% and 15%, respectively. For the years ended December 31, 2015 and 2014, gross margin from our midstream segment totaled $1.81 billion and $1.93

billion, respectively, of which fee-based revenues constituted 86% and 66%, respectively, and non fee-based margin constituted 14% and 34%, respectively. The amount of gross margin earned by our midstream segment from fee-based and non fee-based arrangements (individually and as a percentage of total revenues) will be impacted by the volumes associated with both types of arrangements, as well as commodity prices; therefore, the dollar amounts

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and the relative magnitude of gross margin from fee-based and non fee-based arrangements in future periods may be significantly different from results reported in previous periods.

ITEM 6. EXHIBITS

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

Exhibit Number	Description
5.1	Amendment No. 13 to the Second Amended and Restated Agreement of Limited Partnership of ETP (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed August 2, 2016).
5.2	Amendment No. 12 to the Second Amended and Restated Agreement of Limited Partnership of ETP (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed April 7, 2016).
10.1	Guarantee of Collection, dated as of March 31, 2016, by and between ETP Retail Holdings, LLC and Sunoco LP (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 1, 2016).
10.2	Support Agreement, dated as of March 31, 2016, by and between Sunoco, Inc., Sunoco LP, and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed April 1, 2016).
10.3	Support Agreement, dated as of March 31, 2016, by and between Atlantic Refining & Marketing Corp., Sunoco LP, and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 1, 2016).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

** Furnished herewith.

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SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P., its General Partner

By: Energy Transfer Partners, L.L.C., its General Partner

Date: August 5, 2016 By: /s/ A. Troy Sturrock

A. Troy Sturrock
Vice President, Controller and Principal Accounting Officer
(duly authorized to sign on behalf of the registrant)