Energy Transfer Partners, L.P.
Form 10-Q
May 08, 2015
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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 March 31, 2015
or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-11727
ENERGY TRANSFER PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)
(214) 981-0700
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

At May 1, 2015, the registrant had 499,168,333 Common Units outstanding.

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (the “Partnership,” or “ETP”) in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “estimate,” “goal,” “ “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its general partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Part I – Item 1A. Risk Factors” in the Partnership’s Report on Form 10-K for the year ended December 31, 2014 filed with the Securities and Exchange Commission on March 2, 2015.

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
ET Crude Oil	Energy Transfer Crude Oil Company, LLC, a joint venture owned 60% by ETE and 40% by ETP
ETC Compression	ETC Compression, LLC
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company

ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP Credit Facility	ETP’s $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

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FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
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
MMBtu	million British thermal units
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PEPL Holdings	PEPL Holdings, LLC
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Retail Holdings	ETP Retail Holdings, 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)
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Susser	Susser Holdings Corporation
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, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly-owned subsidiaries based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's proportionate ownership.

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

	March 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,789	$639
Accounts receivable, net	2,464	2,879
Accounts receivable from related companies	127	210
Inventories	1,388	1,389
Exchanges receivable	36	44
Price risk management assets	12	7
Other current assets	390	271
Total current assets	6,206	5,439
PROPERTY, PLANT AND EQUIPMENT	35,304	33,200
ACCUMULATED DEPRECIATION	(3,655)	(3,457)
	31,649	29,743
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,723	3,840
GOODWILL	6,256	6,419
INTANGIBLE ASSETS, net	2,093	2,087
OTHER NON-CURRENT ASSETS, net	702	693
Total assets	$50,629	$48,221

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)

	March 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$2,548	$2,992
Accounts payable to related companies	94	62
Exchanges payable	155	183
Price risk management liabilities	16	21
Accrued and other current liabilities	1,625	1,774
Current maturities of long-term debt	269	1,008
Total current liabilities	4,707	6,040
LONG-TERM DEBT, less current maturities	20,430	18,332
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	214	138
DEFERRED INCOME TAXES	4,036	4,226
OTHER NON-CURRENT LIABILITIES	1,256	1,206
COMMITMENTS AND CONTINGENCIES		
REDEEMABLE NONCONTROLLING INTERESTS	15	15
EQUITY:		
General Partner	282	184
Limited Partners:		
Common Unitholders	9,232	10,430
Class H Unitholder	3,432	1,512
Class I Unitholder	33	—
Accumulated other comprehensive loss	(13)	(56)
Total partners’ capital	12,966	12,070
Noncontrolling interest	7,005	6,194
Total equity	19,971	18,264
Total liabilities and equity	$50,629	$48,221

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 March 31,	
	2015	2014
REVENUES:		
Natural gas sales	$670	$1,103
NGL sales	849	951
Crude sales	2,208	4,093
Gathering, transportation and other fees	686	655
Refined product sales	3,656	4,478
Other	1,461	952
Total revenues	9,530	12,232
COSTS AND EXPENSES:		
Cost of products sold	8,040	10,866
Operating expenses	485	336
Depreciation and amortization	322	266
Selling, general and administrative	100	76
Total costs and expenses	8,947	11,544
OPERATING INCOME	583	688
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(228)	(219)
Equity in earnings of unconsolidated affiliates	40	79
Gain on sale of AmeriGas common units	—	70
Losses on interest rate derivatives	(77)	(2)
Other, net	3	(3)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	321	613
Income tax expense from continuing operations	13	146
INCOME FROM CONTINUING OPERATIONS	308	467
Income from discontinued operations	—	24
NET INCOME	308	491
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	27	76
NET INCOME ATTRIBUTABLE TO PARTNERS	281	415
General Partner’s interest in net income	242	113
Class H Unitholder’s interest in net income	54	49
Class I Unitholder’s interest in net income	33	—
Common Unitholders’ interest in net income (loss)	$(48)	$253
INCOME (LOSS) FROM CONTINUING OPERATIONS PER COMMON UNIT:		
Basic	$(0.17)	$0.69
Diluted	$(0.17)	$0.69
NET INCOME (LOSS) PER COMMON UNIT:		
Basic	$(0.17)	$0.76
Diluted	$(0.17)	$0.76

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 March 31, 2015	2014
Net income	$308	$491
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	—	4
Change in value of derivative instruments accounted for as cash flow hedges	1	(4)
Change in value of available-for-sale securities	1	—
Actuarial gain (loss) relating to pension and other postretirement benefits	45	(1)
Foreign currency translation adjustments	(2)	(3)
Change in other comprehensive income from unconsolidated affiliates	(2)	(7)
	43	(11)
Comprehensive income	351	480
Less: Comprehensive income attributable to noncontrolling interest	27	76
Comprehensive income attributable to partners	$324	$404

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 THREE MONTHS ENDED MARCH 31, 2015
(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, 2014	$184	$10,430	$1,512	$—	$ (56)	$ 6,194	$18,264
Distributions to partners	(145)	(353)	(60)	—	—	—	(558)
Distributions to noncontrolling interest	—	—	—	—	—	(114)	(114)
Units issued for cash	—	135	—	—	—	—	135
Subsidiary units issued for cash	1	71	—	—	—	617	689
Capital contributions from noncontrolling interest	—	—	—	—	—	250	250
Other comprehensive income, net of tax	—	—	—	—	43	—	43
Sale of noncontrolling interest in Rover Pipeline LLC to AE–Midco Rover, LLC	—	4	—	—	—	60	64
Bakken Pipeline Transaction	—	(979)	1,926	—	—	72	1,019
Sunoco Logistics acquisition of noncontrolling interest	—	(30)	—	—	—	(99)	(129)
Other, net	—	2	—	—	—	(2)	—
Net income (loss)	242	(48)	54	33	—	27	308
Balance, March 31, 2015	$282	$9,232	$3,432	$33	$ (13)	$ 7,005	$19,971

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)

	Three Months Ended March 31, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$308	$491
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	322	266
Deferred income taxes	21	(107)
Amortization included in interest expense	(13)	(16)
Inventory valuation adjustments	34	(14)
Non-cash compensation expense	16	14
Gain on sale of AmeriGas common units	—	(70)
Distributions on unvested awards	(3)	(5)
Equity in earnings of unconsolidated affiliates	(40)	(79)
Distributions from unconsolidated affiliates	46	49
Other non-cash	(4)	(6)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	(181)	159
Net cash provided by operating activities	506	682
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash proceeds from Bakken Pipeline Transaction	980	—
Cash paid for acquisition of a noncontrolling interest	(129)	—
Cash paid for all other acquisitions	(370)	—
Cash proceeds from sale of noncontrolling interest in Rover Pipeline LLC to AE–Midco Rover, LLC	64	—
Cash proceeds from the sale of AmeriGas common units	—	381
Capital expenditures (excluding allowance for equity funds used during construction)	(1,686)	(727)
Contributions in aid of construction costs	4	7
Contributions to unconsolidated affiliates	(7)	(43)
Distributions from unconsolidated affiliates in excess of cumulative earnings	32	32
Proceeds from the sale of assets	6	6
Change in restricted cash	—	3
Other	(5)	(24)
Net cash used in investing activities	(1,111)	(365)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	6,303	939
Repayments of long-term debt	(4,928)	(454)
Net proceeds from issuance of Common Units	135	142
Subsidiary equity offerings, net of issue costs	689	—
Capital contributions received from noncontrolling interest	250	40
Distributions to partners	(558)	(481)
Distributions to noncontrolling interest	(114)	(73)
Debt issuance costs	(22)	—
Net cash provided by financing activities	1,755	113
INCREASE IN CASH AND CASH EQUIVALENTS	1,150	430

CASH AND CASH EQUIVALENTS, beginning of period	639	549
CASH AND CASH EQUIVALENTS, end of period	$1,789	$979

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:

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 general partner of our General Partner. 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. ETC OLP's intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP's midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- ETP Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco, Inc. Panhandle and Sunoco, Inc. operations are described as follows:
- Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. In January 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle surviving the merger.
- Sunoco, Inc. owns and operates retail marketing assets, which sell gasoline and middle distillates at retail locations and operates convenience stores primarily on the east coast and in the midwest region of the United States. Effective June 1, 2014, the Partnership combined certain Sunoco, Inc. retail assets with another wholly-owned subsidiary of ETP to form a limited liability company owned by ETP and Sunoco, Inc.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of products, crude oil and NGL pipelines, terminalling and storage assets, and refined products, crude oil and NGL acquisition and marketing assets.
- ETP owns an indirect 100% equity interest in Susser and the general partner interest, incentive distribution rights and a 44% limited partner interest in Sunoco LP. Susser operates convenience stores in Texas, New Mexico and Oklahoma. Sunoco LP distributes motor fuels to convenience stores and retail fuel outlets in Texas, New Mexico,

Oklahoma, Kansas, Louisiana, Maryland, Virginia, Tennessee, Georgia and Hawaii and other commercial customers. These operations are reported within the retail marketing segment.

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Our financial statements reflect the following reportable business segments:

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

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, 2014. 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.

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.

Certain prior period amounts have been reclassified to conform to the 2015 presentation. These reclassifications had no impact on net income or total equity.

We record the collection of taxes to be remitted to government authorities on a net basis except for our retail marketing segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and cost of products sold in the consolidated statements of operations, with no net impact on net income. Excise taxes collected by our retail marketing segment were $736 million and $530 million for the three months ended March 31, 2015 and 2014, respectively.

New Accounting Pronouncement

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, Consolidation (Topic 810) ("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. ASU 2015-02 is effective for fiscal years beginning after December 15, 2015, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2016, and we are currently evaluating the impact that it will have on our consolidated financial statements and related disclosures.

2. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2015 Transactions

Regency Merger

In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.

In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will reduce the incentive distributions it receives from ETP by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

ETP and Regency are under common control of ETE; therefore, we expect to account for the Regency Merger at historical cost as a reorganization of entities under common control. Accordingly, beginning with the quarter ending June 30, 2015,

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ETP's consolidated financial statements will be retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner).

The following table summarizes the assets and liabilities of Regency as of March 31, 2015 and December 31, 2014, which amounts will be retrospectively consolidated in ETP's consolidated balance sheets beginning with the quarter ending June 30, 2015, subject to the elimination of intercompany balances:

	March 31, 2015	December 31, 2014
Current assets	$663	$703
Property, plant and equipment	9,540	9,217
Goodwill	1,223	1,223
Intangible assets	3,405	3,439
Other non-current assets	2,585	2,521
	$17,416	$17,103
Current liabilities	$643	$756
Long-term debt, less current maturities	7,221	6,641
Long-term derivative liabilities	14	16
Other non-current liabilities	74	72
Series A Preferred Units	33	33
Partners' capital and noncontrolling interest	9,431	9,585
	$17,416	$17,103

Dropdown of Sunoco, LLC Interests

In April 2015, Sunoco LP completed the acquisition of a 31.58% equity interest in Sunoco, LLC from Retail Holdings. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. The transaction was valued at approximately $816 million. Sunoco LP paid $775 million in cash and issued $41 million of Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP's common units as of March 20, 2015.

Bakken Pipeline Transaction

In March 2015, ETE transferred 30.8 million ETP Common Units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, ETP also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. The IDR subsidies from ETE to ETP, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

Discontinued Operations

Discontinued operations for the three months ended March 31, 2014 included the results of operations for a marketing business that had been recently acquired and was sold effective April 1, 2014.

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 acquisitions and deconsolidations) included in cash flows from operating activities is comprised as follows:

	Three Months Ended March 31,	
	2015	2014
Accounts receivable	$364	$(751)
Accounts receivable from related companies	92	(23)
Inventories	(40)	338
Exchanges receivable	8	(44)
Other current assets	(130)	39
Other non-current assets, net	35	(15)
Accounts payable	(422)	441
Accounts payable to related companies	(73)	57
Exchanges payable	(28)	(1)
Accrued and other current liabilities	(176)	104
Other non-current liabilities	120	(25)
Price risk management assets and liabilities, net	69	39
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$(181)	$159

Non-cash investing and financing activities are as follows:

	Three Months Ended March 31,	
	2015	2014
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$578	$168
Net gains from subsidiary common unit issuances	$72	$—
NON-CASH FINANCING ACTIVITIES:		
Issuance of Class H Units in connection with the Bakken Pipeline Transaction	$1,926	$—
Redemption of Common Units in connection with the Bakken Pipeline Transaction	$979	$—
Redemption of Common Units in connection with the Lake Charles LNG Transaction	$—	$1,167

4. INVENTORIES:

Inventories consisted of the following:

	March 31, 2015	December 31, 2014
Natural gas and NGLs	$277	$369
Crude oil	470	364
Refined products	367	392
Other	274	264
Total inventories	$1,388	$1,389

5. FAIR VALUE MEASUREMENTS:

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and

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liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the three months ended March 31, 2015, no transfers were made between any levels within the fair value hierarchy. Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations at March 31, 2015 was $22.03 billion and $20.70 billion, respectively. As of December 31, 2014, the aggregate fair value and carrying amount of our consolidated debt obligations was $20.40 billion and $19.34 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of March 31, 2015 and December 31, 2014 based on inputs used to derive their fair values:

		Fair Value Measurements at March 31, 2015	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$6	$—	$6
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	11	11	—
Swing Swaps IFERC	2	—	2
Fixed Swaps/Futures	295	295	—
Forward Physical Swaps	1	—	1
Power:			
Forwards	5	—	5
Futures	4	4	—
Options – Calls	2	2	—
Natural Gas Liquids – Forwards/Swaps	25	25	—
Refined Products – Futures	7	7	—
Crude – Futures	2	2	—
Total commodity derivatives	354	346	8
Total assets	$360	$346	$14
Liabilities:			
Interest rate derivatives	$(226)	$—	$(226)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(10)	(10)	—
Swing Swaps IFERC	(4)	(1)	(3)
Fixed Swaps/Futures	(293)	(293)	—
Power:			
Forwards	(4)	—	(4)
Futures	(3)	(3)	—
Options – Puts	(4)	(4)	—
Natural Gas Liquids – Forwards/Swaps	(22)	(22)	—
Refined Products – Futures	(5)	(5)	—
Crude – Futures	(3)	(3)	—
Total commodity derivatives	(348)	(341)	(7)
Total liabilities	$(574)	$(341)	$(233)

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	Fair Value Total	Fair Value Measurements at December 31, 2014 Level 1	Level 2
Assets:			
Interest rate derivatives	$3	$—	$3
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	19	19	—
Swing Swaps IFERC	26	1	25
Fixed Swaps/Futures	541	541	—
Forward Physical Swaps	1	—	1
Power:			
Forwards	3	—	3
Futures	4	4	—
Natural Gas Liquids – Forwards/Swaps	46	46	—
Refined Products – Futures	21	21	—
Total commodity derivatives	661	632	29
Total assets	$664	$632	$32
Liabilities:			
Interest rate derivatives	$(155)	$—	$(155)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(18)	(18)	—
Swing Swaps IFERC	(25)	(2)	(23)
Fixed Swaps/Futures	(490)	(490)	—
Power:			
Forwards	(4)	—	(4)
Futures	(2)	(2)	—
Natural Gas Liquids – Forwards/Swaps	(32)	(32)	—
Refined Products – Futures	(7)	(7)	—
Total commodity derivatives	(578)	(551)	(27)
Total liabilities	$(733)	$(551)	$(182)

6. NET INCOME 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 are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

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

	Three Months Ended March 31,	
	2015	2014
Income from continuing operations	$308	$467
Less: Income from continuing operations attributable to noncontrolling interest	27	76
Income from continuing operations, net of noncontrolling interest	281	391
General Partner's interest in income from continuing operations	242	113
Class H Unitholder's interest in income from continuing operations	54	49
Class I Unitholder's interest in income from continuing operations	33	—
Common Unitholders' interest in income (loss) from continuing operations	(48)	229
Additional earnings allocated to General Partner	(2)	(1)
Distributions on employee unit awards, net of allocation to General Partner	(4)	(3)
Income (loss) from continuing operations available to Common Unitholders	$(54)	$225
Weighted average Common Units – basic	323.8	324.5
Basic income (loss) from continuing operations per Common Unit	$(0.17)	$0.69
Dilutive effect of unvested Unit Awards	—	1.0
Weighted average Common Units, assuming dilutive effect of unvested Unit Awards	323.8	325.5
Diluted income (loss) from continuing operations per Common Unit	$(0.17)	$0.69
Basic income from discontinued operations per Common Unit	$0.00	$0.07
Diluted income from discontinued operations per Common Unit	$0.00	$0.07

Based on the declared distribution rate of $1.015 per Common Unit, distributions to be paid for the three months ended March 31, 2015 are expected to exceed net income attributable to partners for the period. Due to the closing of the Regency Merger prior to the record date for the distributions to be paid for the three months ended March 31, 2015, the amount of distributions to be paid for the period will include distributions on the Common Units issued in connection with the Regency Merger. The allocation of the distributions in excess of net income is based on the proportionate ownership interests of the Limited Partners and General Partner. Based on this allocation approach, the distributions paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended March 31, 2015, and as a result, net losses were allocated to the Limited Partners for the period.

7. DEBT OBLIGATIONS:

Senior Notes

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In April 2015, Sunoco LP issued $800 million aggregate principal amount of 6.375% senior notes due April 2023. The net proceeds from the offering were used to fund the cash portion of the dropdown of Sunoco, LLC interests.

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 and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. As of March 31, 2015, the ETP Credit Facility had no outstanding borrowings.

On April 30, 2015, ETP borrowed $1.5 billion under the ETP Credit Facility to partially fund the repayment of the Regency Credit Facility.

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Sunoco Logistics Credit Facilities

In March 2015, Sunoco Logistics amended and restated its $1.5 billion unsecured credit facility, which was scheduled to mature in November 2018. The amended and restated credit facility is a $2.5 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 March 31, 2015, the Sunoco Logistics Credit Facility had $350 million of outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.25 billion revolving credit facility (the “Sunoco LP Credit Facility”), which expires in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP’s written request, subject to certain conditions, up to an additional $250 million. As of March 31, 2015, the Sunoco LP Credit Facility had $685 million of outstanding borrowings.

In April 2015, Sunoco LP amended the Sunoco LP Credit Facility to allow for borrowings of up to $1.5 billion.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of March 31, 2015.

8. REDEEMABLE NONCONTROLLING INTERESTS:

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

9. EQUITY:

Class H Units and Class I Units

In March 2015, ETE transferred 30.8 million ETP Common Units, ETE’s 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In connection with this transaction, ETP also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. The IDR subsidies from ETE to ETP, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

The impact of (i) the IDR subsidy adjustments and (ii) the Class I Unit distributions, along with the currently effective IDR subsidies, is included in the table below under “Quarterly Distributions of Available Cash.”

ETP Common Unit Activity

The change in ETP Common Units during the three months ended March 31, 2015 was as follows:

	Number of Units
Number of Common Units at December 31, 2014	355.5
Common Units issued in connection with Equity Distribution Agreements	1.2
Common Units issued in connection with the Distribution Reinvestment Plan	1.0
Common Units redeemed in connection with the Bakken Pipeline Transaction	(30.8)
Number of Common Units at March 31, 2015	326.9

During the three months ended March 31, 2015, the Partnership received proceeds of $76 million, net of commissions of $1 million, from the issuance of units pursuant to equity distribution agreements, which were used for general partnership purposes. As of March 31, 2015, approximately $1.33 billion of the Partnership’s Common Units remained available to be issued under an equity distribution agreement.

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During the three months ended March 31, 2015, distributions of $59 million were reinvested under the Distribution Reinvestment Plan resulting in the issuance of 1.0 million Common Units. As of March 31, 2015, a total of 6.3 million Common Units remain available to be issued under the existing registration statement.

Sales of Common Units by Subsidiaries

With respect to our investments in Sunoco Logistics and Sunoco LP, we account for the difference between the carrying amount of our investment in and the underlying book value arising from the issuance or redemption of units by the respective subsidiary (excluding transactions with us) as capital transactions.

As a result of Sunoco Logistics' issuances of common units during the three months ended March 31, 2015, we recognized increases in partners' capital of $72 million.

Sales of Common Units by Sunoco Logistics

In 2014, Sunoco Logistics entered into equity distribution agreements pursuant to which Sunoco Logistics may sell from time to time common units having aggregate offering prices of up to $1.25 billion. During the three months ended March 31, 2015, Sunoco Logistics received proceeds of $142 million, net of commissions of $1 million, which were used for general partnership purposes.

Additionally, Sunoco Logistics completed a public offering of 13.5 million common units for net proceeds of $547 million in March 2015. The net proceeds were used to repay outstanding borrowings under the $2.5 billion Sunoco Logistics Credit Facility and for general partnership purposes. In April 2015, an additional 2.0 million common units were issued for net proceeds of $82 million related to the exercise of an option in connection with the March 2015 offering.

Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by ETP subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 6, 2015	February 13, 2015	$0.9950
March 31, 2015	May 8, 2015	May 15, 2015	1.0150

In connection with previous transactions, including the Regency Merger, 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
2015 (remainder)	$84
2016	137
2017	145
2018	140
2019	130
2020	35
2021	35
2022	35
2023	35
2024	18

Sunoco Logistics Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 9, 2015	February 13, 2015	$0.4000
March 31, 2015	May 11, 2015	May 15, 2015	0.4190

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Sunoco LP Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by Sunoco LP subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 17, 2015	February 27, 2015	$0.6000
March 31, 2015	May 19, 2015	May 29, 2015	0.6450

Accumulated Other Comprehensive Income (Loss)

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

	March 31, 2015	December 31, 2014
Available-for-sale securities	$4	$3
Foreign currency translation adjustment	(5)	(3)
Net loss on commodity related hedges	—	(1)
Actuarial loss related to pensions and other postretirement benefits	(12)	(57)
Investments in unconsolidated affiliates, net	—	2
Total AOCI, net of tax	$(13)	$(56)

10. INCOME TAXES:

For the three months ended March 31, 2015, the Partnership's income tax expense from continuing operations included favorable state income tax adjustments of $14 million. For the three months ended March 31, 2014 , the Partnership's income tax expense from continuing operations included unfavorable income tax adjustments of $85 million related to the Lake Charles LNG Transaction, which was treated as a sale for tax purposes.

During the three months ended March 31, 2015, Sunoco received a notice of disallowance denying previously filed refund claims related to certain government incentive payments. However, Sunoco intends to file a refund suit with the United States Court of Federal Claims or the United States District Court having jurisdiction. In preparation for filing its complaint to the Court, Sunoco formalized its claims by filing amended Federal income tax returns with the Internal Revenue Service on March 10, 2015. The amended returns include an increase in the claims of $92 million, bringing the total claimed amount to $464 million. This increase relates primarily to the inclusion of certain tax years that were previously regarded as closed for purposes of calculating the potential refund. Consistent with prior treatment, Sunoco has established a reserve for the full amount of the increase due to the uncertain nature of the claims.

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

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

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

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

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

Contingent Residual Support Agreement – AmeriGas

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

Panhandle Guarantee of Collection

Panhandle guarantees the collections of the payment of $600 million of Regency 4.50% senior notes due 2023.

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.

Transwestern Rate Case

On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to the 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in August 2015.

FGT Rate Case

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective May 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015.

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 March 31,	
	2015	2014
Rental expense[(1)]	$47	$31
Less: Sublease rental income	(8)	(8)
Rental expense, net	$39	$23

(1) Includes contingent rentals totaling $4 million and $3 million for the three months ended March 31, 2015 and 2014, 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.

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 are asserting primarily product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. The plaintiffs in all of the cases are seeking to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of March 31, 2015, Sunoco, Inc. is a defendant in five cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, 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. Insufficient information has been developed about the plaintiffs' legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco, Inc. in these matters. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership's consolidated financial position.

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. 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 March 31, 2015 and December 31, 2014, accruals of approximately $39 million and $37 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 March 31, 2015 or December 31, 2014 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.

Environmental Matters

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

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

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

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Environmental Remediation

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

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Currently operating Sunoco, Inc. retail sites.
- 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 March 31, 2015, Sunoco, Inc. had been named as a PRP at approximately 51 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.

	March 31, 2015	December 31, 2014
Current	$46	$39
Non-current	333	352
Total environmental liabilities	$379	$391

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 March 31, 2015 and 2014, Sunoco, Inc. recorded $7 million and $8 million, respectively, of expenditures related to environmental cleanup programs.

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

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

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pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.
Our operations are also subject to the requirements of the OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.
12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:
Commodity Price Risk
We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.
We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.
We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.
We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded

in cost of products sold in the consolidated statement of operations.
We may use derivatives in our liquids transportation and services segment to manage our storage facilities and the purchase and sale of purity NGLs.
Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products, crude and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are

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able and willing to bear it. Sunoco Logistics does not designate any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

We also use derivatives to hedge a variety of price risks in our retail marketing segment. Futures and swaps are used 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. The derivatives used in our retail marketing segment represent economic hedges; however, we have elected not to designate any of these derivative contracts as hedges in this business segment. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

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

The following table details our outstanding commodity-related derivatives:

	March 31, 2015		December 31, 2014	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	775,000	2015	(232,500)	2015
Basis Swaps IFERC/NYMEX[(1)]	3,842,500	2015-2016	(13,907,500)	2015-2016
Options – Calls	5,000,000	2015	5,000,000	2015
Power (Megawatt):				
Forwards	225,131	2015	288,775	2015
Futures	168,992	2015	(156,000)	2015
Options – Puts	(177,942)	2015	(72,000)	2015
Options – Calls	1,742,117	2015	198,556	2015
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	13,292,500	2015-2016	57,500	2015
Swing Swaps IFERC	51,465,000	2015-2016	46,150,000	2015
Fixed Swaps/Futures	1,705,000	2015-2016	(8,779,000)	2015-2016
Forward Physical Contracts	23,903,779	2015	(9,116,777)	2015
Natural Gas Liquid and Crude (Bbls) – Forwards/Swaps	(768,100)	2015-2016	(2,179,400)	2015
Refined Products (Bbls) – Futures	(1,019,000)	2015	13,745,755	2015
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(23,295,000)	2016	(39,287,500)	2015
Fixed Swaps/Futures	(23,475,000)	2016	(39,287,500)	2015
Hedged Item – Inventory	23,475,000	2016	39,287,500	2015

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(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.

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 March 31, 2015	Notional Amount Outstanding December 31, 2014
July 2015[2]	Forward-starting to pay a fixed rate of 3.40% and receive a floating rate	$100	$200
July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	200
July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	300
July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
July 2019[4]	Forward-starting to pay a fixed rate of 3.01% and receive a floating rate	500	300
March 2019	Pay a floating rate based on 3-month LIBOR and receive a fixed rate of 1.53%	600	—
February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	—	200

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

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

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

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

Credit Risk

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

The Partnership’s counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities and midstream companies. 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.

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

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2015	December 31, 2014	March 31, 2015	December 31, 2014
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$3	$43	$—	$—
	3	43	—	—
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	347	617	(346)	(577)
Commodity derivatives	20	23	(18)	(23)
Interest rate derivatives	6	3	(226)	(155)
	373	643	(590)	(755)
Total derivatives	$376	$686	$(590)	$(755)

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

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	March 31, 2015	December 31, 2014	March 31, 2015	December 31, 2014
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$20	$23	$(18)	$(23)
Broker cleared derivative contracts	Other current assets	334	674	(356)	(574)
		354	697	(374)	(597)
Offsetting agreements:					
Counterparty netting	Price risk management assets (liabilities)	(14)	(19)	14	19
Payments on margin deposit	Other current assets	30	5	(4)	(22)
		16	(14)	10	(3)
Net derivatives with offsetting agreements		370	683	(364)	(600)
Derivatives without offsetting agreements		6	3	(226)	(155)
Total derivatives		$376	$686	$(590)	$(755)

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 March 31, 2015	2014
Derivatives in cash flow hedging relationships:		
Commodity derivatives	$1	$(4)
Total	$1	$(4)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended March 31, 2015	2014
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$—	$(4)
Total		$—	$(4)

	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 March 31, 2015	2014
Derivatives in fair value hedging relationships (including hedged item):			
Commodity derivatives	Cost of products sold	$(3)	$(6)
Total		$(3)	$(6)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives Three Months Ended March 31, 2015	2014
Derivatives not designated as hedging instruments:			
Commodity derivatives – Trading	Cost of products sold	$(2)	$7
Commodity derivatives – Non-trading	Cost of products sold	(19)	7
Interest rate derivatives	Losses on interest rate derivatives	(77)	(2)
Total		$(98)	$12

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13. RELATED PARTY TRANSACTIONS:

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

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

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

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

	Three Months Ended March 31,	
	2015	2014
Affiliated revenues	$130	$341

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

	March 31, 2015	December 31, 2014
Accounts receivable from related companies:		
ETE	$12	$11
Regency	40	74
PES	21	6
FGT	15	9
Lake Charles LNG	3	3
Other	36	107
Total accounts receivable from related companies:	$127	$210
Accounts payable to related companies:		
Regency	$71	$53
FGT	3	2
Lake Charles LNG	3	2
Other	17	5
Total accounts payable to related companies:	$94	$62

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14. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	March 31, 2015	December 31, 2014
Deposits paid to vendors	$62	$65
Deferred income taxes	11	14
Income taxes receivable	110	17
Prepaid expenses and other	207	175
Total other current assets	$390	$271

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	March 31, 2015	December 31, 2014
Interest payable	$290	$301
Customer advances and deposits	75	82
Accrued capital expenditures	571	536
Accrued wages and benefits	113	196
Taxes payable other than income taxes	240	236
Income taxes payable	37	50
Deferred income taxes	99	99
Other	200	274
Total accrued and other current liabilities	$1,625	$1,774

15. 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
- 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

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Logistics segment are primarily reflected in crude sales. Revenues from our retail marketing segment are primarily reflected in refined product sales.

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

The following tables present financial information by segment:

	Three Months Ended March 31,	
	2015	2014
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$550	$847
Intersegment revenues	36	87
	586	934
Interstate transportation and storage:		
Revenues from external customers	271	295
Intersegment revenues	5	3
	276	298
Midstream:		
Revenues from external customers	255	302
Intersegment revenues	276	351
	531	653
Liquids transportation and services:		
Revenues from external customers	813	801
Intersegment revenues	18	29
	831	830
Investment in Sunoco Logistics:		
Revenues from external customers	2,526	4,452
Intersegment revenues	46	25
	2,572	4,477
Retail marketing:		
Revenues from external customers	4,782	5,008
Intersegment revenues	23	3
	4,805	5,011
All other:		
Revenues from external customers	333	527
Intersegment revenues	50	64
	383	591
Eliminations	(454)	(562)
Total revenues	$9,530	$12,232

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	Three Months Ended March 31, 2015	2014
Segment Adjusted EBITDA:		
Intrastate transportation and storage	$162	$177
Interstate transportation and storage	277	300
Midstream	153	126
Liquids transportation and services	166	128
Investment in Sunoco Logistics	221	208
Retail marketing	129	109
All other	41	158
Total	1,149	1,206
Depreciation and amortization	(322)	(266)
Interest expense, net of interest capitalized	(228)	(219)
Gain on sale of AmeriGas common units	—	70
Losses on interest rate derivatives	(77)	(2)
Non-cash unit-based compensation expense	(16)	(14)
Unrealized losses on commodity risk management activities	(66)	(29)
Inventory valuation adjustments	(34)	14
Adjusted EBITDA related to discontinued operations	—	(27)
Adjusted EBITDA related to unconsolidated affiliates	(127)	(196)
Equity in earnings of unconsolidated affiliates	40	79
Other, net	2	(3)
Income from continuing operations before income tax expense	$321	$613

	March 31, 2015	December 31, 2014
Assets:		
Intrastate transportation and storage	$4,541	$4,563
Interstate transportation and storage	10,521	10,082
Midstream	4,096	3,548
Liquids transportation and services	5,750	4,581
Investment in Sunoco Logistics	13,799	13,619
Retail marketing	8,573	8,930
All other	3,349	2,898
Total assets	$50,629	$48,221

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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, 2014 filed with the SEC on March 2, 2015; and (iii) our management's discussion and analysis of financial condition and results of operations included in our 2014 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, 2014.

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

OVERVIEW

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

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger, CrossCountry and ET Rover Pipeline LLC. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- Liquids operations, including NGL transportation, storage and fractionation services primarily through Lone Star.
- Product and crude oil operations, including the following:
  - product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco, Inc., Susser and Sunoco LP.

RECENT DEVELOPMENTS

Lone Star Fractionator IV

In May 2015, we announced that our subsidiary, Lone Star, would construct a fourth NGL fractionation facility at Mont Belvieu, Texas. Fractionator IV, estimated to cost approximately $450 million, is scheduled to be operational by December 2016. The 120,000 Bbls/d fractionator is fully subscribed by multiple long-term contracts and will provide off-take for the new 533-mile, 24- and 30-inch Lone Star Express pipeline.

Sunoco Logistics Bakken Pipeline Exchange

In May 2015, ETP announced that it has reached agreement for Sunoco Logistics to participate in the Bakken Pipeline project, which is jointly owned by ETP and Phillips 66. The project consists of existing and newly constructed pipelines that are expected to provide aggregate takeaway capacity of approximately 470,000 Bbls/d of crude oil from the Bakken/Three Forks production area in North Dakota to key refinery and terminalling hubs in the Midwest and Gulf Coast, including Sunoco Logistics' Nederland terminal. The ultimate takeaway capacity for the project is 570,000 Bbls/d. The pipeline system is supported by long-term fee based contracts and is expected to begin commercial operations in the fourth quarter of 2016. Sunoco Logistics will fund its proportionate share of the construction costs and is expected to have a 30% interest in project. ETP also anticipates reaching agreement for Sunoco Logistics to become the operator of the pipeline system. The agreement is subject to closing conditions customary to transactions of this nature and we anticipate closing to be finalized during the second quarter of 2015.

Regency Merger

In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new

ETP Series A Preferred Units.

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In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will reduce the incentive distributions it receives from ETP by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

ETP and Regency are under common control of ETE; therefore, we expect to account for the Regency Merger at historical cost as a reorganization of entities under common control. Accordingly, beginning with the quarter ending June 30, 2015, ETP's consolidated financial statements will be retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner).

Dropdown of Sunoco, LLC Interests

In April 2015, Sunoco LP completed the acquisition of a 31.58% equity interest in Sunoco, LLC from Retail Holdings. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. The transaction was valued at approximately $816 million. Sunoco LP paid $775 million in cash and issued $41 million of Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP's common units as of March 20, 2015.

Bakken Pipeline Transaction

In March 2015, ETE transferred 30.8 million ETP Common Units, ETE's 45% interest in the Bakken pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the "Bakken Pipeline Transaction"). In connection with this transaction, ETP also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. The IDR subsidies from ETE to ETP, including the impact from distributions on Class I Units, will be reduced by $55 million in 2015 and $30 million in 2016.

Quarterly Cash Distribution Increase

In April 2015, ETP announced that its Board of Directors approved an increase in its quarterly distribution to $1.015 per ETP Common Unit ($4.06 annualized) for the quarter ended March 31, 2015, representing an increase of $0.32 per ETP Common Unit on an annualized basis compared to the first quarter of 2014.

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Results of Operations
Consolidated Results

	Three Months Ended March 31, 2015	2014	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$162	$177	$(15)
Interstate transportation and storage	277	300	(23)
Midstream	153	126	27
Liquids transportation and services	166	128	38
Investment in Sunoco Logistics	221	208	13
Retail marketing	129	109	20
All other	41	158	(117)
Total	1,149	1,206	(57)
Depreciation and amortization	(322)	(266)	(56)
Interest expense, net of interest capitalized	(228)	(219)	(9)
Gain on sale of AmeriGas common units	—	70	(70)
Losses on interest rate derivatives	(77)	(2)	(75)
Non-cash unit-based compensation expense	(16)	(14)	(2)
Unrealized losses on commodity risk management activities	(66)	(29)	(37)
Inventory valuation adjustments	(34)	14	(48)
Adjusted EBITDA related to discontinued operations	—	(27)	27
Adjusted EBITDA related to unconsolidated affiliates	(127)	(196)	69
Equity in earnings of unconsolidated affiliates	40	79	(39)
Other, net	2	(3)	5
Income from continuing operations before income tax expense	321	613	(292)
Income tax expense from continuing operations	(13)	(146)	133
Income from continuing operations	308	467	(159)
Income from discontinued operations	—	24	(24)
Net income	$308	$491	$(183)

See the detailed discussion of Segment Adjusted EBITDA below in Segment Operating Results.

Depreciation and Amortization. Depreciation and amortization expense increased for the three months ended March 31, 2015 compared to the same period last year primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Gain on Sale of AmeriGas Common Units. In January 2014, the Partnership recognized a gain on the sale of 9.2 million AmeriGas common units that were originally received in connection with the contribution of our propane business to AmeriGas in 2012. As of March 31, 2015, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Losses on Interest Rate Derivatives. Losses on interest rate derivatives during the three months ended March 31, 2015 and 2014, respectively, resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value.

Unrealized Losses on Commodity Risk Management Activities. See discussion of the unrealized 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 and our retail marketing operations as a result of commodity price changes between periods.

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Adjusted EBITDA Related to Discontinued Operations. Amounts for the three months ended March 31, 2014 related to a marketing business that was sold effective April 1, 2014.
Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. See additional information in "Supplemental Information on Unconsolidated Affiliates" and "Segment Operating Results" below.
Other, net. Includes amortization of regulatory assets and other income and expense amounts.
Income Tax Expense from Continuing Operations. Income tax expense is based on the earnings of our taxable subsidiaries. In addition, the three months ended March 31, 2014 included the impact of the Lake Charles LNG Transaction, which was treated as a sale for tax purposes, resulting in $85 million of incremental income tax expense.
Supplemental Pro Forma Financial Information
The following unaudited pro forma consolidated financial information of ETP has been prepared in accordance with Article 11 of Regulation S-X and reflects the pro forma impacts of the Regency Merger for the three months ended March 31, 2015 and 2014 assuming that the merger occurred on January 1, 2014. This unaudited pro forma financial information is provided to supplement the discussion and analysis of the historical financial information and should be read in conjunction with such historical financial information. This unaudited pro forma financial information is for illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Regency Merger had been consummated on January 1, 2014.
The following table presents pro forma financial information for the three months ended March 31, 2015:

	ETP Historical	Regency Historical	Pro Forma Adjustments	ETP Pro Forma for Regency Merger
REVENUES	$9,530	$999	$(203)	$10,326
COSTS AND EXPENSES:				
Cost of products sold	8,040	641	(194)	8,487
Operating expenses	485	133	1	619
Depreciation and amortization	322	158	(1)	479
Selling, general and administrative	100	36	(3)	133
Total costs and expenses	8,947	968	(197)	9,718
OPERATING INCOME	583	31	(6)	608
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(228)	(82)	—	(310)
Equity in earnings of unconsolidated affiliates	40	50	(33)	57
Losses on interest rate derivatives	(77)	—	—	(77)
Other, net	3	3	1	7
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	321	2	(38)	285
Income tax expense from continuing operations	13	5	(1)	17
INCOME FROM CONTINUING OPERATIONS	$308	$(3)	$(37)	$268

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The following table presents pro forma financial information for the three months ended March 31, 2014:

	ETP Historical	Regency Historical	Pro Forma Adjustments	ETP Pro Forma for Regency Merger
REVENUES	$12,232	$863	$(68)	$13,027
COSTS AND EXPENSES:				
Cost of products sold	10,866	638	(62)	11,442
Operating expenses	336	78	—	414
Depreciation and amortization	266	94	—	360
Selling, general and administrative	76	33	(4)	105
Gain on asset sales, net	—	(2)	2	—
Total costs and expenses	11,544	841	(64)	12,321
OPERATING INCOME	688	22	(4)	706
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(219)	(56)	1	(274)
Equity in earnings of unconsolidated affiliates	79	43	(18)	104
Gain on sale of AmeriGas common units	70	—	—	70
Losses on interest rate derivatives	(2)	—	—	(2)
Other, net	(3)	2	1	—
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	613	11	(20)	604
Income tax expense (benefit) from continuing operations	146	(1)	—	145
INCOME FROM CONTINUING OPERATIONS	$467	$12	$(20)	$459

The pro forma adjustments reflect the following:

- Adjustments to eliminate related party balances and transactions between ETP and Regency, including commercial transactions, as well as fees for services provided under an operating and service agreement between ETP and Regency.
- Adjustments to eliminate Regency’s equity in earnings from its investment in Lone Star, because Lone Star is a consolidated subsidiary of ETP.
- Pro forma adjustment to eliminate equity in earnings from ETP’s investment in Regency. ETP indirectly owns 31.4 million Regency common units and all of the outstanding Regency Class F units, and these limited partner interests converted to limited partner interests in ETP upon the closing of the merger.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended March 31, 2015	2014	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$19	$18	$1
FEP	14	14	—
Regency	4	(7)	11
PES	(9)	17	(26)
AmeriGas	6	34	(28)
Other	6	3	3
Total equity in earnings of unconsolidated affiliates	$40	$79	$(39)
Adjusted EBITDA related to unconsolidated affiliates[1]:			
Citrus	$69	$68	$1
FEP	19	19	—
Regency	23	27	(4)
PES	2	23	(21)
AmeriGas	—	51	(51)
Other	14	8	6
Total Adjusted EBITDA related to unconsolidated affiliates	$127	$196	$(69)
Distributions received from unconsolidated affiliates:			
Citrus	$33	$34	$(1)
FEP	16	16	—
Regency	16	15	1
PES	2	—	2
AmeriGas	—	11	(11)
Other	8	5	3
Total distributions received from unconsolidated affiliates	$75	$81	$(6)

(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.

Segment Operating Results

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

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

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Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

- Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- Adjusted EBITDA related to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for the year ended December 31, 2014 filed with the SEC on March 2, 2015.

Intrastate Transportation and Storage

	Three Months Ended March 31,		
	2015	2014	Change
Natural gas transported (MMBtu/d)	8,809,018	9,399,267	(590,249)
Revenues	$586	$934	$(348)
Cost of products sold	416	734	(318)
Gross margin	170	200	(30)
Unrealized losses on commodity risk management activities	35	27	8
Operating expenses, excluding non-cash compensation expense	(36)	(42)	6
Selling, general and administrative expenses, excluding non-cash compensation expense	(7)	(7)	—
Adjusted EBITDA related to unconsolidated affiliates	—	(1)	1
Segment Adjusted EBITDA	$162	$177	$(15)

Volumes. For the three months ended March 31, 2015, transported volumes declined compared to the same period last year primarily due to lower production from certain key shippers in the Barnett Shale region.

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

	Three Months Ended March 31,		
	2015	2014	Change
Transportation fees	$128	$117	$11
Natural gas sales and other	24	41	(17)
Retained fuel revenues	15	30	(15)
Storage margin, including fees	3	12	(9)
Total gross margin	$170	$200	$(30)

Intrastate transportation and storage gross margin decreased $30 million for the three months ended March 31, 2015 compared to the same period last year due to the impact of the following:

- Transportation fees. Transportation fees increased for the three months ended March 31, 2015 primarily due to increased revenue from long-term fixed capacity fee contracts on our Houston pipeline system resulting from the renegotiation of existing contracts, as well as the initiation of new contracts.
- Natural gas sales and other. Margin from natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, gains and losses on derivatives used to hedge net retained fuel, and the margin from gas sales, processing and gathering fees on our Houston pipeline system. For the three months ended March 31, 2015, margin from natural gas sales and other decreased $17 million primarily due to a decrease in gains from derivatives.

- Retained fuel revenues. Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased $15 million for the three months ended March 31, 2015 compared to the same period last year primarily due to the impact of the cold winter season in early 2014, which drove up prices during the three months ended March 31, 2014. The average spot price at the Houston Ship Channel location for the three months ended March 31, 2015 decreased by $2.31/MMBtu, or 46%, to $2.77/MMBtu as compared to $5.08/MMBtu for the same period last year.

Storage margin was comprised of the following:

	Three Months Ended March 31, 2015	2014	Change
Withdrawals from storage natural gas inventory (MMBtu)	15,782,500	37,891,036	(22,108,536)
Realized margin on natural gas inventory transactions	$35	$34	$1
Fair value inventory adjustments	12	(11)	23
Unrealized losses on derivatives	(51)	(18)	(33)
Margin recognized on natural gas inventory, including related derivatives	(4)	5	(9)
Revenues from fee-based storage	7	7	—
Total storage margin	$3	$12	$(9)

For the three months ended March 31, 2015 compared to the same period last year, the decrease in storage margin was principally driven by a decline in the spreads between the spot price of our natural gas inventory held at the Bammel storage facility in relation to the market value of the forward contracts used to hedge that inventory.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized gains and losses on commodity risk management activities reflect the net impact from storage and non-storage derivatives, as well as fair value adjustments to inventory. We experienced a decrease of $8 million in the margin from unrealized gains and losses on commodity risk management activities for the three months ended March 31, 2015 compared to the same period last year.

For the three months ended March 31, 2015, unrealized losses from commodity risk management activities of $35 million consisted of unrealized losses of $47 million from storage and non-storage related derivatives, partially offset by a gain of $12 million on the fair value adjustment to hedged storage gas inventory. Unrealized losses from storage related activities were primarily offset by realized margin on natural gas inventory transactions as illustrated in the storage margin table above. For the three months ended March 31, 2014, the unrealized loss of $27 million included unrealized losses from storage and non-storage related derivatives of $16 million, and unrealized losses from the fair value adjustments to storage gas inventory of $11 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased for the three months ended March 31, 2015 compared to the same period last year primarily due to a decrease in fuel consumption expense of approximately $6 million driven by a decrease in fuel market prices.

Interstate Transportation and Storage

	Three Months Ended March 31, 2015	2014	Change
Natural gas transported (MMBtu/d)	6,763,691	6,956,089	(192,398)
Natural gas sold (MMBtu/d)	16,656	15,783	873
Revenues	$276	$298	$(22)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(72)	(71)	(1)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(15)	(14)	(1)
Adjusted EBITDA related to unconsolidated affiliates	88	87	1
Segment Adjusted EBITDA	$277	$300	$(23)

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Volumes. For the three months ended March 31, 2015 compared to the same period last year, transported volumes decreased primarily due to warmer weather in 2015 along the Panhandle pipeline, resulting in a decrease of 137,508 MMBtu/d, and declines in supply into the Sea Robin pipeline as a result of a customer maintenance related outage, resulting in a decrease of 78,260 MMBtu/d. These decreases in volumes transported were partially offset by higher volumes transported on the Tiger pipeline of 32,106 MMBtu/d due to storage withdrawals in the Midwest as a result of colder weather.

Revenues. The decreases in volumes transported, as discussed above, did not significantly impact revenues, which are primarily fixed fees for the reservation of capacity on the pipelines. Interstate transportation and storage revenues decreased for the three months ended March 31, 2015 compared to the same period last year primarily due to lower transportation loan-related revenues of approximately $23 million as a result of higher basis differentials in 2014 driven by the colder weather.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation and storage operating expenses increased due to an increase in fuel consumption of $4 million, increased employee-related costs of $2 million and increased maintenance costs of $2 million. These increases were offset by a decrease in ad valorem taxes of $7 million.

Midstream

	Three Months Ended March 31,		
	2015	2014	Change
Gathered volumes (MMBtu/d)	3,657,371	2,558,851	1,098,520
NGLs produced (Bbls/d)	202,370	136,818	65,552
Equity NGLs (Bbls/d)	14,320	12,106	2,214
Revenues	$531	$653	$(122)
Cost of products sold	346	493	(147)
Gross margin	185	160	25
Operating expenses, excluding non-cash compensation expense	(30)	(28)	(2)
Selling, general and administrative expenses, excluding non-cash compensation expense	(2)	(6)	4
Segment Adjusted EBITDA	$153	$126	$27

Volumes. Gathered volumes, NGLs produced and equity NGLs produced increased during the three months ended March 31, 2015 compared to the same period last year primarily due to increased production by our customers in the Eagle Ford Shale and the recent startup of the Rebel plant in the Permian Basin.

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

	Three Months Ended March 31,		
	2015	2014	Change
Gathering and processing fee-based revenues	$161	$123	$38
Non fee-based contracts and processing	24	37	(13)
Total gross margin	$185	$160	$25

Midstream gross margin increased for the three months ended March 31, 2015 compared to the same period last year due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale and Permian Basin resulted in an increase in fee-based revenues of $33 million. In addition, fee-based margin also increased $6 million primarily due to a change in contract terms on our Southeast Texas system where certain contracts were converted from non fee-based terms to fee-based.
- Non fee-based contracts and processing. Lower commodity prices resulted in a decrease of $24 million, which was partially offset by a $9 million increase in equity volumes due to production in the Eagle Ford Shale and Permian Basin.

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Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased for the three months ended March 31, 2015 compared to the same period last year primarily due to additional expense from assets recently placed in service.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses decreased for the three months ended March 31, 2015 compared to the same period last year primarily due to a reduction in employee-related costs.

Liquids Transportation and Services

	Three Months Ended March 31,		
	2015	2014	Change
Liquids transportation volumes (Bbls/d)	438,646	307,511	131,135
NGL fractionation volumes (Bbls/d)	226,041	156,898	69,143
Revenues	$831	$830	$1
Cost of products sold	637	671	(34)
Gross margin	194	159	35
Unrealized losses on commodity risk management activities	9	1	8
Operating expenses, excluding non-cash compensation expense	(35)	(28)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(4)	(5)	1
Adjusted EBITDA related to unconsolidated affiliates	2	1	1
Segment Adjusted EBITDA	$166	$128	$38

Volumes. For the three months ended March 31, 2015 compared to the same period last year, NGL transportation volumes increased approximately 98,000 Bbls/d on our wholly-owned and joint venture pipelines due to an increase in NGL production from our Jackson processing plants and volumes transported to our Mont Belvieu, Texas facilities via our Justice pipeline. The remainder of the increase was from volumes transported out of west Texas on our Lone Star pipeline system as producers ramped up volumes.

Average daily fractionated volumes increased for the three months ended March 31, 2015 compared to the same period last year due to the ramp-up of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas, which was commissioned in October 2013. These volumes include all physical and contractual volumes where we collected a fractionation fee.

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

	Three Months Ended March 31,		
	2015	2014	Change
Transportation margin	$81	$59	$22
Processing and fractionation margin	65	49	16
Storage margin	44	40	4
Other margin	4	11	(7)
Total gross margin	$194	$159	$35

Liquids transportation and services gross margin increased for the three months ended March 31, 2015 compared to the same period last year due to the following:

- Transportation margin. For the three months ended March 31, 2015, transportation margin increased $11 million due to higher volumes transported out of west Texas and the Eagle Ford Shale on our Lone Star pipeline system, $9 million due to increases in NGL production from our processing plants that connect to various fractionators via our wholly-owned pipelines, and $2 million due to the recent commissioning of our wholly-owned crude pipeline.
- Processing and fractionation margin. For the three months ended March 31, 2015, processing and fractionation margin increased primarily due to the ramp-up of Lone Star’s second fractionator at Mont Belvieu, Texas, which was commissioned in October 2013.

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- Storage margin. For the three months ended March 31, 2015, storage margin reflected increases of approximately $6 million due to increased demand for leased storage capacity as a result of market conditions and higher ancillary fees associated with throughput volumes of $2 million. These increases in fee based storage margin were offset by a decrease of $4 million from lower non fee-based storage activities, including blending activities.
- Other margin. For the three months ended March 31, 2015, other margin decreased primarily due to the impact of the cold winter season in early 2014.

Operating Expenses, Excluding Non-Cash Compensation Expense. Liquids transportation and services operating expenses increased for the three months ended March 31, 2015 compared to the same period last year primarily due to the ramp-up of Lone Star's second fractionator in Mont Belvieu, Texas, which was commissioned in October 2013.

Investment in Sunoco Logistics

	Three Months Ended March 31,		
	2015	2014	Change
Revenues	$2,572	$4,477	$(1,905)
Cost of products sold	2,350	4,210	(1,860)
Gross margin	222	267	(45)
Unrealized (gains) losses on commodity risk management activities	15	(1)	16
Operating expenses, excluding non-cash compensation expense	(48)	(39)	(9)
Selling, general and administrative expenses, excluding non-cash compensation expense	(22)	(27)	5
Inventory valuation adjustments	41	—	41
Adjusted EBITDA related to unconsolidated affiliates	13	8	5
Segment Adjusted EBITDA	$221	$208	$13

Segment Adjusted EBITDA. For the three months ended March 31, 2015 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 $19 million from crude oil acquisition and marketing activities, primarily due to an increase of $17 million from higher realized crude margins and an increase of $1 million from increased crude oil volumes resulting from recent acquisitions and the expansion of the crude oil trucking fleet;
- an increase of $26 million from products pipelines, primarily due to an increase of $12 million from higher throughput volumes and higher average pipeline revenue per barrel of $10 million, which were largely driven by contributions from Sunoco Logistics' Mariner NGL pipeline projects, and increased contributions from Sunoco Logistics' joint venture interests of $5 million; and
- an increase of $2 million from crude oil pipelines, primarily due to higher throughput volumes of $10 million largely driven by expansion projects placed into service in Texas and Oklahoma during 2014, largely offset by lower average pipeline revenue per barrel of $7 million, which was impacted by reduced volumes on higher-priced tariff movements; partially offset by
- a decrease of $34 million from terminal facilities, primarily due to lower results from products acquisition and marketing activities of $45 million. Sunoco Logistics utilized its storage capabilities to increase its level of certain refined products inventories in order to capture the contango market structure. These inventory positions, combined with the timing of butane blending sales, were negatively impacted by inventory valuation adjustments. This decrease in operating results was partially offset by higher contributions from Sunoco Logistics' bulk marine and refined products terminals of $10 million.

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Retail Marketing

	Three Months Ended March 31, 2015	2014	Change
Retail gasoline outlets, end of period:			
Total	6,683	5,122	1,561
Company-operated	1,258	529	729
Motor fuel sales:			
Total gallons (in millions)	1,881	1,392	489
Company-operated (gallons/month per site)	156,456	178,448	(21,992)
Motor fuel gross profit (cents/gallon):			
Total	12.9	8.4	4.5
Company-operated	26.0	22.1	3.9
Merchandise sales	$481	$140	$341
Revenues	$4,805	$5,011	$(206)
Cost of products sold	4,367	4,756	(389)
Gross margin	438	255	183
Unrealized losses on commodity risk management activities	2	3	(1)
Operating expenses, excluding non-cash compensation expense	(271)	(126)	(145)
Selling, general and administrative expenses, excluding non-cash compensation expense	(34)	(10)	(24)
Inventory valuation adjustments	(7)	(14)	7
Adjusted EBITDA related to unconsolidated affiliates	1	1	—
Segment Adjusted EBITDA	$129	$109	$20

Gross Margin. For the three months ended March 31, 2015 compared to the same period last year, retail marketing gross margin included the favorable impact of recent acquisitions, including $184 million from the acquisition of Susser in August 2014 and $34 million from other acquisitions. Retail marketing gross margin also increased from stronger retail and wholesale motor fuel margins and other retail margins of $33 million and $4 million, respectively. These increases were partially offset by a decrease of $45 million due to exceptionally strong results in 2014 from ethanol manufacturing and blending, largely related to weather related impacts and regional market dynamics as well as unfavorable impacts related to non-retail fuel activities and non-cash inventory valuation adjustments of $20 million and $7 million, respectively.

Operating Expenses, Excluding Non-Cash Compensation Expense. Retail marketing operating expenses increased for the three months ended March 31, 2015 compared to the same period last year primarily due to recent acquisitions.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Retail marketing selling, general and administrative expenses increased for the three months ended March 31, 2015 compared to the same period last year primarily due to recent acquisitions.

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

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All Other

	Three Months Ended March 31,		
	2015	2014	Change
Revenues	$383	$591	$(208)
Cost of products sold	374	564	(190)
Gross margin	9	27	(18)
Unrealized (gains) losses on commodity risk management activities	5	(1)	6
Operating expenses, excluding non-cash compensation expense	5	(5)	10
Selling, general and administrative expenses, excluding non-cash compensation expense	(18)	(11)	(7)
Adjusted EBITDA related to discontinued operations	—	27	(27)
Adjusted EBITDA related to unconsolidated affiliates	25	102	(77)
Other	19	19	—
Elimination	(4)	—	(4)
Segment Adjusted EBITDA	$41	$158	$(117)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing and compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture; and
- our investment in Regency common and Class F units; and
- our investment in AmeriGas until August 2014.

For the three months ended March 31, 2015 compared to the same period last year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $77 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to a decrease of $51 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2014 and lower earnings from our investment in PES of $21 million; and
- Adjusted EBITDA related to discontinued operations of $27 million in the prior period related to a marketing business that was sold effective April 1, 2014.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. These fees were reflected in "Other" in the "All other" segment and for the three months ended March 31, 2015 were reflected as an offset to operating expenses of $6 million and selling, general and administrative expenses of $13 million in the consolidated statements of operations.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

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We currently expect capital expenditures (net of contributions in aid of construction costs) for the full year 2015 to be within the following ranges, including Regency's expected capital expenditures:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage	$150	$200	$30	$35
Interstate transportation and storage[2]	750	850	100	115
Midstream	1,900	2,000	90	110
Liquids transportation and services:				
NGL[3]	1,700	1,750	25	30
Crude[2]	700	750	—	—
Retail marketing[4]	200	250	80	100
All other (including eliminations)	200	250	35	45
Total direct capital expenditures	5,600	6,050	360	435
Indirect[1]:				
Investment in Sunoco Logistics	2,400	2,600	65	75
Investment in Sunoco LP[4]	180	230	15	25
Total indirect capital expenditures	2,580	2,830	80	100
Total projected capital expenditures	$8,180	$8,880	$440	$535

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

(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipeline projects.

(3) Includes 100% of Lone Star's capital expenditures.

(4) The retail marketing segment includes the investment in Sunoco LP, as well as ETP's wholly-owned retail marketing operations. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

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 or a combination thereof.

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a

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

Three months ended March 31, 2015 compared to three months ended March 31, 2014. Cash provided by operating activities during 2015 was $506 million compared to $682 million for 2014 and net income was $308 million and $491 million for 2015 and 2014, respectively. The difference between net income and cash provided by operating activities for the three months ended March 31, 2015 primarily consisted of net changes in operating assets and liabilities of $181 million and non-cash items totaling $336 million.

The non-cash activity in 2015 and 2014 consisted primarily of depreciation and amortization of $322 million and $266 million, respectively, non-cash compensation expense of $16 million and $14 million, respectively, and equity in earnings of unconsolidated affiliates of $40 million and $79 million, respectively. Non-cash activity in 2015 also included deferred income taxes of $21 million and inventory valuation adjustments of $34 million.

Cash paid for interest, net of interest capitalized, was $273 million and $268 million for the three months ended March 31, 2015 and 2014, respectively.

Capitalized interest was $27 million and $15 million for the three months ended March 31, 2015 and 2014, 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.

Three months ended March 31, 2015 compared to three months ended March 31, 2014. Cash used in investing activities during 2015 was $1.11 billion compared to $365 million for 2014. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2015 were $1.68 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2014 of $720 million. Additional detail related to our capital expenditures is provided in the table below. During 2015, we received $980 million in cash related to the Bakken Pipeline Transaction and paid $499 million in cash for all other acquisitions. Additionally, during 2014, we received proceeds of $381 million from sales of AmeriGas common units.

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The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the three months ended March 31, 2015, excluding Regency's capital expenditures:

	Capital Expenditures Recorded During Period			(Increase) Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Direct[1]:					
Intrastate transportation and storage	$15	$3	$18	$11	$29
Interstate transportation and storage[2]	271	19	290	(5)	285
Midstream	248	4	252	(11)	241
Liquids transportation and services[2][3]	559	4	563	(79)	484
Retail marketing[4]	73	14	87	13	100
All other (including eliminations)	10	—	10	(67)	(57)
Total direct capital expenditures	1,176	44	1,220	(138)	1,082
Indirect[1]:					
Investment in Sunoco Logistics	416	15	431	130	561
Investment in Sunoco LP[4]	36	3	39	—	39
Total indirect capital expenditures	452	18	470	130	600
Total capital expenditures	$1,628	$62	$1,690	$(8)	$1,682

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

(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipeline projects.

(3) Includes 100% of Lone Star's capital expenditures. We received $63 million in cash for capital contributions from Regency related to its 30% interest in Lone Star during the three months ended March 31, 2015.

(4) The retail marketing segment includes the investment in Sunoco LP, as well as ETP's wholly-owned retail marketing operations. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

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.

Three months ended March 31, 2015 compared to three months ended March 31, 2014. Cash provided by financing activities during 2015 was $1.76 billion compared to $113 million for 2014. In 2015 and 2014, we received net proceeds from Common Unit offerings of $135 million and $142 million, respectively. In 2015, our subsidiaries received $689 million in net proceeds from the issuance of common units. During 2015, we had a net increase in our debt level of $1.38 billion compared to a net increase of $485 million for 2014. We have paid distributions of $558 million to our partners in 2015 compared to $481 million in 2014. We have also paid distributions of $114 million to noncontrolling interests in 2015 compared to $73 million in 2014. In addition, we have received capital contributions of $250 million in cash from noncontrolling interests in 2015 compared to $40 million in 2014. We incurred debt issuance costs of $22 million in 2015.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2015	December 31, 2014
ETP Senior Notes	$12,640	$10,890
Transwestern Senior Notes	782	782
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	715	715
Sunoco Logistics Senior Notes	3,975	3,975
Revolving credit facilities:		
ETP $3.75 billion Revolving Credit Facility due November 2019	—	570
Sunoco Logistics’ subsidiary $35 million Revolving Credit Facility due April 2015	35	35
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020	350	150
Sunoco LP $1.25 billion Revolving Credit Facility due September 2019	685	683
Other long-term debt	220	223
Unamortized premiums, net of discounts and fair value adjustments	212	232
Total debt	20,699	19,340
Less: Current maturities of long-term debt	269	1,008
Long-term debt, less current maturities	$20,430	$18,332

Senior Notes

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to pay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In April 2015, Sunoco LP issued $800 million aggregate principal amount of 6.375% senior notes due April 2023. The net proceeds from the offering were used to fund the cash portion of the dropdown of Sunoco, LLC interests.

Regency Debt

The following table reflects outstanding indebtedness assumed in the Regency Merger:

	April 30, 2015
Regency Senior Notes	$5,088
Regency Credit Facility	—
Unamortized premiums, net of discounts and fair value adjustments	43
Total debt	$5,131

On April 30, 2015, the Regency Credit Facility was repaid and terminated.

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 and not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our current and future unsecured debt. As of March 31, 2015, the ETP Credit Facility had no outstanding borrowings.

On April 30, 2015, ETP borrowed $1.5 billion under the ETP Credit Facility to partially fund the repayment of the Regency Credit Facility.

Sunoco Logistics Credit Facilities

In March 2015, Sunoco Logistics amended and restated its $1.5 billion unsecured credit facility, which was scheduled to mature in November 2018. The amended and restated credit facility is a $2.5 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 March 31, 2015, the Sunoco Logistics Credit Facility had $350 million of outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.25 billion revolving credit facility (the "Sunoco LP Credit Facility"), which expires in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of March 31, 2015, the Sunoco LP Credit Facility had $685 million of outstanding borrowings.

In April 2015, Sunoco LP amended the Sunoco LP Credit Facility to allow for borrowings of up to $1.5 billion.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of March 31, 2015.

CASH DISTRIBUTIONS

Cash Distributions Paid by ETP

We expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders. Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash (as defined in our Partnership Agreement) for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations.

Following are distributions declared and/or paid by us subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 6, 2015	February 13, 2015	$0.9950
March 31, 2015	May 8, 2015	May 15, 2015	1.0150

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

	Three Months Ended March 31,	
	2015	2014
Common Units held by public[(1)]	465	266
Common Units held by ETE	24	29
Class H Units held by ETE and ETE Holdings	56	50
General Partner interest held by ETE	8	5
Incentive distributions held by ETE	300	168
IDR relinquishments net of Class I Unit distributions	(27)	(57)
Total distributions declared to the partners of ETP	$826	$461

(1) Reflects the impact from Common Units issued in the Regency Merger.

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In connection with transactions previous transactions, including the Regency Merger, 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
2015 (remainder)	$84
2016	137
2017	145
2018	140
2019	130
2020	35
2021	35
2022	35
2023	35
2024	18

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, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 9, 2015	February 13, 2015	$0.4000
March 31, 2015	May 11, 2015	May 15, 2015	0.4190

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

	Three Months Ended March 31,	
	2015	2014
Limited Partners:		
Common units held by public	$75	$49
Common units held by ETP	28	23
General Partner interest held by ETP	3	2
Incentive distributions held by ETP	59	37
Total distributions declared	$165	$111

Cash Distributions Paid by Sunoco LP

Sunoco LP 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 LP subsequent to December 31, 2014:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2014	February 17, 2015	February 27, 2015	$0.6000
March 31, 2015	May 19, 2015	May 29, 2015	0.6450

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

	Three Months Ended March 31, 2015
Limited Partners:	
Common units held by public	$13
Common units held by ETP	10
General Partner interest and incentive distributions held by ETP	2
Total distributions declared	$25

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, 2014, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2014. Since December 31, 2014, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

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

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	March 31, 2015			December 31, 2014		
	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	775,000	$(1)	$—	(232,500)	$(1)	$—
Basis Swaps IFERC/NYMEX[1]	3,842,500	1	—	(13,907,500)	—	—
Options – Calls	5,000,000	—	—	5,000,000	—	—
Power (Megawatt):						
Forwards	225,131	1	1	288,775	—	1
Futures	168,992	—	1	(156,000)	2	—
Options – Puts	(177,942)	(4)	1	(72,000)	—	1
Options – Calls	1,742,117	2	1	198,556	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	13,292,500	—	—	57,500	(3)	—
Swing Swaps IFERC	51,465,000	(2)	1	46,150,000	2	1
Fixed Swaps/Futures	1,705,000	(17)	1	(8,779,000)	4	2
Forward Physical Contracts	23,903,779	1	6	(9,116,777)	—	3
Natural Gas Liquid and Crude (Bbls) – Forwards/Swaps	(768,100)	2	3	(2,179,400)	13	9
Refined Products (Bbls) – Futures	(1,019,000)	2	10	13,745,755	15	11
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(23,295,000)	1	—	(39,287,500)	3	1
Fixed Swaps/Futures	(23,475,000)	20	7	(39,287,500)	48	12

(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 March 31, 2015, we had $1.68 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $17 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

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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 March 31, 2015	December 31, 2014
July 2015[2]	Forward-starting to pay a fixed rate of 3.40% and receive a floating rate	$100	$200
July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	200
July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	300
July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
July 2019[4]	Forward-starting to pay a fixed rate of 3.01% and receive a floating rate	500	300
March 2019	Pay a floating rate based on 3-month LIBOR and receive a fixed rate of 1.53%	600	—
February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	—	200

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

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

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

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

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $257 million as of March 31, 2015. For the $600 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $25 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 March 31, 2015 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 March 31, 2015 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, 2014 and Note 11 – 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 March 31, 2015.

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, 2014.

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ITEM 6. EXHIBITS

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

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated January 25, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners, GP, L.P., Regency Energy Partners LP, Regency GP LP and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed January 26, 2015)
2.2	Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Rendezvous I LLC, Rendezvous II LLC, Regency Energy Partners LP, Regency GP LP, ETE GP Acquirer LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 to the Registrant's Form 8-K filed February 19, 2015)
3.1	Amendment No. 9, dated March 9, 2015, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed March 10, 2015)
4.1	Indenture, dated as of January 18, 2005, among Energy Transfer Partners, L.P., as issuer, the Subsidiary Guarantors, named therein, and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed on January 19, 2005)
4.2	Fourteenth Supplemental Indenture dated as of March 12, 2015 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on March 12, 2015)
10.1	Commitment Increase Agreement by and among Energy Transfer Partners, L.P., the lenders party thereto and Wells Fargo Bank, National Association, in its capacity as administrative agent for the lenders dated February 10, 2015 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed February 17, 2015)
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: May 8, 2015

By: /s/ Thomas E. Long
Thomas E. Long
Chief Financial Officer (duly authorized to sign on behalf of the registrant)