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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2010

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 and 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 ☒ 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☐ 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	☒	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 ☒

At August 3, 2010, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 180,638,718 Common Units

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FORM 10-Q

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. ("Energy Transfer Partners" or "the Partnership") in periodic press releases and some oral statements of Energy Transfer Partners, officials during presentations about the Partnership, include certain "forward-looking" statements. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect" "continue," "estimate," "forecast," "may," "will" or similar expressions help identify forward -looking statements. Although the Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such expectations will prove to be correct.

Actual results may differ materially from any results projected, 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 II Other Information – Item 1A. Risk Factors" in this Quarterly Report on Form 10-Q as well as "Part I – Item 1A. Risk Factors" in the Partnership's Report on Form 10-K for the year ended December 31, 2009 filed with the Securities and Exchange Commission ("SEC") on February 24, 2010.

Definitions

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

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement. A therm factor is 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
Dth	million British thermal units ("dekatherm").
Mcf	thousand cubic feet
MMBtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 78,808	$ 68,183
Marketable securities	3,002	6,055
Accounts receivable, net of allowance for doubtful accounts of $6,378 and $6,338 as of June 30, 2010 and December 31, 2009, respectively	471,288	566,522
Accounts receivable from related companies	49,520	57,369
Inventories	231,057	389,954
Exchanges receivable	9,985	23,136
Price risk management assets	24	12,371
Other current assets	91,112	148,373
Total current assets	934,796	1,271,963
PROPERTY, PLANT AND EQUIPMENT	10,329,313	9,649,405
ACCUMULATED DEPRECIATION	(1,126,660)	(979,158)
	9,202,653	8,670,247
ADVANCES TO AND INVESTMENTS IN AFFILIATES	7,587	663,298
LONG-TERM PRICE RISK MANAGEMENT ASSETS	4,237	—
GOODWILL	773,745	745,505
INTANGIBLES AND OTHER ASSETS, net	433,072	383,959
Total assets	$11,356,090	$ 11,734,972

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 315,601	$ 358,997
Accounts payable to related companies	7,623	38,842
Exchanges payable	11,323	19,203
Price risk management liabilities	2,248	442
Accrued and other current liabilities	459,146	365,168
Current maturities of long-term debt	40,693	40,887
Total current liabilities	836,634	823,539
LONG-TERM DEBT, less current maturities	6,049,443	6,176,918
OTHER NON-CURRENT LIABILITIES	134,385	134,807
COMMITMENTS AND CONTINGENCIES (Note 13)		
PARTNERS' CAPITAL:		
General Partner	172,153	174,884
Limited Partners:		
Common Unitholders (180,136,652 and 179,274,747 units authorized, issued and outstanding at June 30, 2010 and December 31, 2009, respectively)	4,147,705	4,418,017
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary and reported as treasury units)	—	—
Accumulated other comprehensive income	15,770	6,807
Total partners' capital	4,335,628	4,599,708
Total liabilities and partners' capital	$11,356,090	$ 11,734,972

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
REVENUES:				
Natural gas operations	$ 1,045,946	$ 948,233	$ 2,352,655	$ 2,060,188
Retail propane	197,147	179,770	730,586	667,677
Other	24,613	23,814	56,446	54,052
Total revenues	1,267,706	1,151,817	3,139,687	2,781,917
COSTS AND EXPENSES:				
Cost of products sold – natural gas operations	654,239	542,004	1,566,845	1,274,117
Cost of products sold – retail propane	110,282	78,070	415,263	298,292
Cost of products sold – other	6,336	5,919	13,614	12,723
Operating expenses	169,533	176,681	340,281	358,454
Depreciation and amortization	83,877	76,174	167,153	148,777
Selling, general and administrative	44,255	53,749	93,009	109,481
Total costs and expenses	1,068,522	932,597	2,596,165	2,201,844
OPERATING INCOME	199,184	219,220	543,522	580,073
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(103,014)	(100,680)	(207,976)	(182,725)
Equity in earnings of affiliates	4,072	1,673	10,253	2,170
Gains (losses) on disposal of assets	1,385	181	(479)	(245)
Gains on non-hedged interest rate derivatives	—	36,842	—	50,568
Allowance for equity funds used during construction	4,298	(1,839)	5,607	18,588
Impairment of investment in affiliate	(52,620)	—	(52,620)	—
Other, net	(5,893)	(100)	(4,860)	967
INCOME BEFORE INCOME TAX EXPENSE	47,412	155,297	293,447	469,396
Income tax expense	4,569	4,559	10,493	11,491
NET INCOME	42,843	150,738	282,954	457,905
GENERAL PARTNER’S INTEREST IN NET INCOME	90,599	87,179	190,598	177,469
LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS)	$ (47,756)	$ 63,559	$ 92,356	$ 280,436
BASIC NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ (0.26)	$ 0.38	$ 0.48	$ 1.72
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	186,649,074	166,596,074	187,531,919	161,829,139
DILUTED NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ (0.26)	$ 0.38	$ 0.48	$ 1.72
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	186,649,074	167,197,121	188,362,188	162,384,831

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	$ 42,843	$ 150,738	$ 282,954	$ 457,905
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(6,112)	856	(12,618)	(9,693)
Change in value of derivative instruments accounted for as cash flow hedges	(9,452)	1,336	24,634	(50)
Change in value of available-for-sale securities	(724)	3,657	(3,053)	3,708
	(16,288)	5,849	8,963	(6,035)
Comprehensive income	$ 26,555	$ 156,587	$ 291,917	$ 451,870

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2010
(Dollars in thousands)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2009	$ 174,884	$ 4,418,017	$ 6,807	$4,599,708
Redemption of units in connection with MEP Transaction (See Note 1)	(3,700)	(608,340)	—	(612,040)
Distributions to partners	(198,573)	(340,061)	—	(538,634)
Units issued for cash	—	574,522	—	574,522
Capital contribution from General Partner (payment of contributions receivable)	8,932	—	—	8,932
Distributions on unvested unit awards	—	(2,264)	—	(2,264)
Tax effect of remedial income allocation from tax amortization of goodwill	—	(1,701)	—	(1,701)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	14,563	—	14,563
Non-cash executive compensation	12	613	—	625
Other comprehensive income	—	—	8,963	8,963
Net income	190,598	92,356	—	282,954
Balance, June 30, 2010	$ 172,153	$ 4,147,705	$ 15,770	$4,335,628

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 884,001	$ 702,680
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(153,385)	(6,362)
Capital expenditures (excluding allowance for equity funds used during construction)	(608,497)	(512,534)
Contributions in aid of construction costs	7,957	2,349
Advances to affiliates, net of repayments	(5,596)	(364,000)
Proceeds from the sale of assets	9,124	5,033
Net cash used in investing activities	(750,397)	(875,514)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	265,642	1,587,943
Principal payments on debt	(410,142)	(1,501,487)
Net proceeds from issuance of Limited Partner units	574,522	578,924
Capital contribution from General Partner	8,932	3,354
Distributions to partners	(538,634)	(465,827)
Redemption of units	(23,299)	—
Debt issuance costs	—	(7,746)
Net cash provided by (used in) financing activities	(122,979)	195,161
INCREASE IN CASH AND CASH EQUIVALENTS	10,625	22,327
CASH AND CASH EQUIVALENTS, beginning of period	68,183	91,902
CASH AND CASH EQUIVALENTS, end of period	$ 78,808	$ 114,229

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2009, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries ("Energy Transfer Partners," the "Partnership," "we" or "ETP") as of June 30, 2010 and for the three and six months ended June 30, 2010 and 2009, have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners, L.P. and its subsidiaries as of June 30, 2010, and the Partnership's results of operations and cash flows for the three and six months ended June 30, 2010 and 2009. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the SEC on February 24, 2010.

Certain prior period amounts have been reclassified to conform to the 2010 presentation. These reclassifications had no impact on net income or total partners' capital.

We are managed by our general partner, Energy Transfer Partners GP, L.P. (our "General Partner" or "ETP GP"), which is in turn managed by its general partner, Energy Transfer Partners, L.L.C. ("ETP LLC"). Energy Transfer Equity, L.P., a publicly traded master limited partnership ("ETE"), owns ETP LLC, the general partner of our General Partner. The condensed consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the "Operating Companies") as follows:

- La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company ("ETC OLP"), a Texas limited partnership 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, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- Energy Transfer Interstate Holdings, LLC ("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 Pipeline Company, LLC ("Transwestern"), a Delaware limited liability company engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

- ETC Fayetteville Express Pipeline, LLC ("ETC FEP"), a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC ("ETC Tiger"), a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- ETC Compression, LLC ("ETC Compression"), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Heritage Operating, L.P. ("HOLP"), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan Energy Partners, L.P. ("Titan"), a Delaware limited partnership also engaged in retail propane operations.

Recent Developments

On May 26, 2010, we completed the transfer of the membership interests in ETC Midcontinent Express Pipeline III, L.L.C. ("ETC MEP III") to ETE pursuant to the Redemption and Exchange Agreement between us and ETE, dated as of May 10, 2010 (the "MEP Transaction"). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC ("MEP"), our joint venture with Kinder Morgan Energy Partners, L.P. ("KMP") that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, we redeemed 12,273,830 ETP common units that were previously owned by ETE. We also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. This closing adjustment is subject to change during a final review period as defined in the contribution agreement. We also granted ETE an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. ("ETC MEP II"). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of our interest in ETC MEP III, we recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP ("Regency") in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc. ("GE EFS").

We continue to guarantee 50% of MEP's obligations under MEP's $175.4 million senior revolving credit facility, with the remaining 50% of MEP's obligations guaranteed by KMP; however, Regency has agreed to indemnify us for any costs related to the guaranty of payments under this facility. See Note 13.

2. ESTIMATES:

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

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the three and six months ended June 30, 2010 represent the actual results in all material respects.

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

3. ACQUISITIONS:

During the six months ended June 30, 2010, we purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, we recorded customer contracts of $68.2 million and goodwill of $27.3 million. See further discussion at Note 6.

4. CASH, CASH EQUIVALENTS AND SUPPLEMENTAL CASH FLOW INFORMATION:

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

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

Net cash provided by operating activities is comprised of the following:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income	$ 282,954	$ 457,905
Reconciliation of net income to net cash provided by operating activities:		
Impairment of investment in affiliate	52,620	—
Proceeds from termination of interest rate derivatives	15,395	—
Depreciation and amortization	167,153	148,777
Amortization of finance costs charged to interest	4,381	4,152
Non-cash unit-based compensation expense	14,600	14,483
Non-cash executive compensation expense	625	625
Deferred income taxes	155	9,703
Losses on disposal of assets	479	245
Allowance for equity funds used during construction	(5,607)	(18,588)
Distributions on unvested awards	(2,264)	(1,387)
Distributions in excess of (less than) equity in earnings of affiliates, net	20,378	(430)
Other non-cash	1,118	2,167
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	96,767	200,132
Accounts receivable from related companies	7,849	(19,240)
Inventories	159,540	84,695
Exchanges receivable	13,151	17,613
Other current assets	57,263	47,206
Intangibles and other assets	3,615	(2,043)
Accounts payable	(51,622)	(108,183)
Accounts payable to related companies	(11,412)	(27,323)
Exchanges payable	(7,880)	(31,843)
Accrued and other current liabilities	35,925	25,954
Other non-current liabilities	(583)	(155)
Price risk management liabilities, net	29,401	(101,785)
Net cash provided by operating activities	$ 884,001	$ 702,680

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 73,432	$ 90,268
Transfer of MEP joint venture interest in exchange for redemption of Common Units	$ 588,741	$ —
NON-CASH FINANCING ACTIVITIES:		
Capital contribution receivable from general partner	$ —	$ 8,932

5. INVENTORIES:

Inventories consisted of the following:

	June 30, 2010	December 31, 2009
Natural gas and NGLs, excluding propane	$ 89,751	$ 157,103
Propane	49,016	66,686
Appliances, parts and fittings and other	92,290	166,165
Total inventories	$ 231,057	$ 389,954

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

6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

A net increase in goodwill of $28.2 million was recorded during the six months ended June 30, 2010, primarily due to $27.3 million from the acquisition of the natural gas gathering company referenced in Note 3, which is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $68.2 million with useful lives of 46 years.

Components and useful lives of intangibles and other assets were as follows:

	June 30, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 245,574	$ (67,178)	$ 176,858	$ (58,761)
Noncompete agreements (3 to 15 years)	22,931	(12,578)	24,139	(12,415)
Patents (9 years)	750	(76)	750	(35)
Other (10 to 15 years)	1,320	(440)	478	(397)
Total amortizable intangible assets	270,575	(80,272)	202,225	(71,608)
Non-amortizable intangible assets — Trademarks	76,086	—	75,825	—
Total intangible assets	346,661	(80,272)	278,050	(71,608)
Other assets:				
Financing costs (3 to 30 years)	68,657	(29,104)	68,597	(24,774)
Regulatory assets	107,193	(12,508)	101,879	(9,501)
Other	32,445	—	41,316	—
Total intangibles and other assets	$ 554,956	$ (121,884)	$ 489,842	$ (105,883)

Aggregate amortization expense of intangible and other assets was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Reported in depreciation and amortization	$ 5,148	$ 4,983	$ 10,294	$ 9,692
Reported in interest expense	$ 2,165	$ 2,048	$ 4,330	$ 3,926

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

Years Ending December 31:	
2011	$ 26,915
2012	23,330
2013	17,899
2014	16,890
2015	14,566

7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at June 30, 2010 was $6.55 billion and $6.09 billion, respectively. At December 31, 2009, the aggregate fair value and carrying amount of long-term debt was $6.75 billion and $6.22 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("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 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2010 and December 31, 2009 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at June 30, 2010 Using: Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Fair Value Measurements at June 30, 2010 Using: Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 3,002	$ 3,002	$ —
Interest rate derivatives	7,031	—	7,031
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	24	—	24
Swing Swaps IFERC	1,425	1,425	—
Fixed Swaps/Futures	1,045	1,045	—
Options – Puts	19,241	—	19,241
Total commodity derivatives	21,735	2,470	19,265
Total Assets	$ 31,768	$ 5,472	$ 26,296
Liabilities:			
Interest rate derivatives	$ (205)	$ —	$ (205)
Commodity derivatives:			
Natural Gas:			
Basic Swaps IFERC/NYMEX	(454)	(454)	—
Swing Swaps IFERC	(167)	—	(167)
Fixed Swaps/Futures	(181)	—	(181)
Options – Calls	(6,142)	—	(6,142)
Propane – Forwards/Swaps	(4,489)	—	(4,489)
Total commodity derivatives	(11,433)	(454)	(10,979)
Total Liabilities	$ (11,638)	$ (454)	$ (11,184)

	Fair Value Total	Fair Value Measurements at December 31, 2009 Using: Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Fair Value Measurements at December 31, 2009 Using: Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 6,055	$ 6,055	$ —
Commodity derivatives	32,479	20,090	12,389
Liabilities:			
Commodity derivatives	(8,016)	(7,574)	(442)
Total	$ 30,518	$ 18,571	$ 11,947

In conjunction with the MEP Transaction, we adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of our investment was transferred to ETE. See "Recent Developments" at Note 1.

8. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline, LLC

On May 26, 2010, we transferred to ETE, in exchange for ETP common units owned by ETE, substantially all of our interest in MEP. In conjunction with this transfer, we recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest to its estimated fair value. See discussion of the transaction in “Recent Developments” at Note 1.

Fayetteville Express Pipeline, LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Panola County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC (“FEP”), the entity formed to construct, own and operate this pipeline, received Federal Energy Regulatory Commission (“FERC”) approval of its application for authority to construct and operate this pipeline. The pipeline is expected to have an initial capacity of 2.0 Bcf/d and is expected to be in service by the end of 2010. As of June 30, 2010, FEP has secured binding commitments for a minimum of 10 years for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (“NGPL”) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

9. NET INCOME (LOSS) PER LIMITED PARTNER UNIT:

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	$ 42,843	$ 150,738	$ 282,954	$ 457,905
General Partner's interest in net income	90,599	87,179	190,598	177,469
Limited Partners' interest in net income (loss)	(47,756)	63,559	92,356	280,436
Additional earnings allocated (to) from General Partner	(161)	—	636	—
Distributions on employee unit awards, net of allocation to General Partner	(1,152)	(651)	(2,309)	(1,349)
Net income (loss) available to Limited Partners	$ (49,069)	$ 62,908	$ 90,683	$ 279,087
Weighted average Limited Partner units – basic	186,649,074	166,596,074	187,531,919	161,829,139
Basic net income (loss) per Limited Partner unit	$ (0.26)	$ 0.38	$ 0.48	$ 1.72
Weighted average Limited Partner units	186,649,074	166,596,074	187,531,919	161,829,139
Dilutive effect of unit grants	—	601,047	830,269	555,692
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	186,649,074	167,197,121	188,362,188	162,384,831
Diluted net income (loss) per Limited Partner unit	$ (0.26)	$ 0.38	$ 0.48	$ 1.72

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended June 30, 2010 are expected to be $256.2 million in total, which exceeds net income for the period by $213.3 million. Accordingly, the distributions expected to be paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended June 30, 2010, and as a result, a net loss was allocated to the Limited Partners for the period.

10. DEBT OBLIGATIONS:

Revolving Credit Facilities

ETP Credit Facility

We maintain a revolving credit facility (the "ETP Credit Facility") that provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of June 30, 2010, there was $29.3 million of borrowings outstanding under the ETP Credit Facility. Taking into account letters of credit of approximately $21.8 million, the amount available for future borrowings was $1.95 billion. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 0.95%.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility. At June 30, 2010, the HOLP credit facility had no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of June 30, 2010 was $74.5 million.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at June 30, 2010.

11. PARTNERS' CAPITAL:

Common Units Issued

The change in Common Units during the six months ended June 30, 2010 was as follows:

	Number of Units
Balance, December 31, 2009	179,274,747
Common Units issued in connection with public offerings	9,775,000
Common Units issued in connection with the Equity Distribution Agreement	3,340,783
Issuance of Common Units under equity incentive plans	19,952
Redemption of units in connection with MEP Transaction (See Note 1)	(12,273,830)
Balance, June 30, 2010	180,136,652

In January 2010, we issued 9,775,000 Common Units through a public offering. The proceeds of $423.6 million from the offering were used primarily to repay borrowings under the ETP Credit Facility and to fund capital expenditures related to pipeline projects.

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC ("UBS"). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During the six months ended June 30, 2010, we issued 3,340,783 of our Common Units pursuant to this agreement. The proceeds of approximately $151.0 million, net of commissions, were used for general partnership purposes. In addition, we initiated trades on an additional 501,500 of our Common Units that had not settled as of June 30, 2010. Approximately $40.6 million of our Common Units remain available to be issued under the agreement based on trades initiated through June 30, 2010.

Quarterly Distributions of Available Cash

Distributions paid by us are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2009	February 8, 2010	February 15, 2010	$0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at the close of business on August 9, 2010.

The total amounts of distributions declared during the six months ended June 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30,	
	2010	2009
Limited Partners:		
Common Units	$ 332,371	$ 301,738
Class E Units	6,242	6,242
General Partner Interest	9,754	9,720
Incentive Distribution Rights	184,751	168,311
Total distributions declared by ETP	$ 533,118	$ 486,011

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income (“AOCI”), net of tax:

	June 30, 2010	December 31, 2009
Net gains on commodity related hedges	$ 14,353	$ 1,991
Net losses on interest rate hedges	(471)	(125)
Unrealized gains on available-for-sale securities	1,888	4,941
Total AOCI, net of tax	$ 15,770	$ 6,807

12. INCOME TAXES:

The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Current expense (benefit):				
Federal	$ 1,599	$ (771)	$ 2,917	$ (5,107)
State	4,248	3,377	7,421	6,895
Total	5,847	2,606	10,338	1,788
Deferred expense (benefit):				
Federal	(997)	2,041	421	9,142
State	(281)	(88)	(266)	561
Total	(1,278)	1,953	155	9,703
Total income tax expense	$ 4,569	$ 4,559	$ 10,493	$ 11,491
Effective tax rate	9.64%	2.94%	3.58%	2.45%

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level.

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

Regulatory Matters

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline. The application was approved in April 2010 and construction began in June 2010. In February 2010, we announced a 400 MMcf/d expansion of the Tiger pipeline. In June 2010, we filed an application for FERC authority to construct, own and operate that expansion.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (“NGA”) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern’s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

Guarantees

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the “MEP Facility”), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although we transferred substantially all of our interest in MEP on May 26, 2010, as discussed above in “Recent Developments” at Note 1, we will continue to guarantee 50% of MEP’s obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify us for any costs related to the guarantee of payments under this facility.

Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP’s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of June 30, 2010, MEP had $33.1 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility, respectively. Our contingent obligations with respect to our 50% guarantee of MEP's outstanding borrowings and letters of credit were $16.6 million and $16.6 million, respectively, as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 1.4%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the "FEP Facility"). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012 and amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of June 30, 2010, FEP had $663.0 million of outstanding borrowings issued under the FEP Facility and our contingent obligation with respect to our 50% guarantee of FEP's outstanding borrowings was $331.5 million as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts. In addition, we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a contract to purchase not less than 90.0 million gallons of propane per year that expires in 2015. 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 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.4 million and $5.5 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, rental expense for operating leases totaled approximately $11.3 million and $11.5 million, respectively.

Our propane operations have an agreement with Enterprise GP Holdings L.P. ("Enterprise") (see Note 15) to supply a portion of our propane requirements. The agreement expired in March 2010 and our propane operations executed a five year extension as of April 2010. The extension will continue until March 2015 and includes an option to extend the agreement for an additional year.

We have commitments to make capital contributions to our joint ventures. For the joint ventures that we currently have interests in, we expect that capital contributions for the remainder of 2010 will be between $20 million and $30 million.

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 propane are flammable, combustible gases. 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.

FERC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the "Order and Notice") that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC's then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP's trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against us by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ's recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ's fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, ETP remains a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The Plaintiff appealed this determination to the First Court of

Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010, the First Circuit Court of Appeals issued an opinion affirming the judgment of the lower court granting ETP's motion for summary judgment. No motion for rehearing was timely filed.

In October 2007, a consolidated class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint. No petition for rehearing was timely filed.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted our motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obligated to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations and our liquidity.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were defendants in litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the "Cushion Gas Litigation." In 2004, ETC OLP (a subsidiary of ETP) acquired the HPL Entities from AEP, at which time AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A under this court decision.

Other Matters. In addition to those matters described above, 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, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of June 30, 2010 and December 31, 2009, accruals of approximately $11.4 million and $11.1 million, respectively, were recorded related to deductibles. 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 it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

No amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters and deductibles.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that can 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 natural gas pipeline, gathering, treating, compressing, blending and processing business. 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. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage, and to limit the financial liability, which could result from such events. However, the risk of environmental or other damage is inherent in the transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products , as it is with other entities engaged in similar businesses.

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 clean-up 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.

As of June 30, 2010 and December 31, 2009, accruals on an undiscounted basis of $12.5 million and $12.6 million, respectively, were recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities.

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 clean-up costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean-up activities include remediation of several compressor sites on the Transwestern system for historical contamination associated with polychlorinated biphenyls ("PCBs") and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.5 million, which is included in the aggregate environmental accruals. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the U.S. Environmental Protection Agency's (the "EPA") Spill Prevention, Control and Countermeasures ("SPCC") program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

By March 2013, the Texas Commission on Environmental Quality is required to develop another plan to address the recent change in the ozone standard from 0.08 parts per million, or ppm, to 0.075 ppm and the U.S. Environmental Protection Agency, or EPA, recently proposed lowering the standard even further, to somewhere in between 0.06 and 0.07 ppm. These efforts may result in the adoption of new regulations that may require additional nitrogen oxide emissions reductions.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT") under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended June 30, 2010 and 2009, $3.6 million and $11.6 million, respectively, of capital costs and $4.4 million and $5.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the six months ended June 30, 2010 and 2009, $5.0 million and $15.3 million, respectively, of capital costs and $6.3 million and $9.0 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. 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 even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act, also known as 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.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

We are exposed to market risks related to the volatility of natural gas, NGL and propane 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 the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage and interstate segments to hedge the sales price of retention and operational gas sales and hedge location price differentials related to the transportation of natural gas.
- Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot 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 or the physical withdrawal of natural gas.

The recent adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Part II, Item 1A. Risk Factors of this Form 10-Q.

We are also exposed to market risk on gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income 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 attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

The following table details the outstanding commodity-related derivatives:

	June 30, 2010		December 31, 2009	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(23,182,500)	2010-2011	72,325,000	2010-2011
Swing Swaps IFERC (MMBtu)	(23,592,500)	2010-2011	(38,935,000)	2010
Fixed Swaps/Futures (MMBtu)	(395,000)	2010-2011	4,852,500	2010-2011
Options – Puts (MMBtu)	(8,140,000)	2010-2011	2,640,000	2010
Options – Calls (MMBtu)	(5,920,000)	2010-2011	(2,640,000)	2010
Propane:				
Forwards/Swaps (Gallons)	—	—	6,090,000	2010
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(5,410,000)	2010-2011	(22,625,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,765,000)	2010-2011	(27,300,000)	2010
Hedged Item – Inventory (MMBtu)	18,765,000	2010	27,300,000	2010
Cash Flow Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(10,845,000)	2010-2011	(13,225,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,502,500)	2010-2011	(22,800,000)	2010
Options – Puts (MMBtu)	25,800,000	2011-2012	—	—
Options – Calls (MMBtu)	(25,800,000)	2011-2012	—	—
Propane:				
Forwards/Swaps (Gallons)	51,702,000	2010-2011	20,538,000	2010

We expect gains of $11.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps in order to achieve our desired mix of fixed and variable rate debt. We also utilize interest rate swaps to lock in the rate on a portion of our anticipated debt issuances. We have the following interest rate swaps outstanding as of June 30, 2010:

Term	Notional Amount	Type [(1)]	Hedge Designation
July 2013	$350,000	Pay a floating rate plus 3.75% and receive a fixed rate of 6.00%	Fair value
August 2012	200,000	Forward starting to pay a fixed rate of 3.80% and receive a floating rate	Cash flow

(1) Floating rates are based on LIBOR.

In May 2010, the Partnership terminated interest rate swaps with notional amounts of $750.0 million that were designated as fair value hedges. Proceeds from the swap termination were $15.4 million. In connection with the swap termination, $9.7 million of previously recorded fair value adjustments to the hedged long-term debt will be amortized as a reduction of interest expense through February 2015.

Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of June 30, 2010 and December 31, 2009:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2010	December 31, 2009	June 30, 2010	December 31, 2009
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$25,158	$ 669	$ (4,425)	$ (24,035)
Commodity derivatives	—	8,443	(4,625)	(201)
Interest rate derivatives	7,031	—	(205)	—
	32,189	9,112	(9,255)	(24,236)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	32,257	72,851	(37,877)	(36,950)
Commodity derivatives	24	3,928	(212)	(241)
	32,281	76,779	(38,089)	(37,191)
Total derivatives	$64,470	$ 85,891	$(47,344)	$ (61,427)

The commodity derivatives (margin deposits) are recorded in "Other current assets" on our condensed consolidated balance sheets. The remainder of the derivatives are recorded in "Price risk management assets/liabilities."

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

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market 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 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 condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $44.4 million and $79.7 million as of June 30, 2010 and December 31, 2009, respectively.

The following tables detail the effect of the Partnership's derivative assets and liabilities in the condensed consolidated statements of operations for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$ (9,150)	$ 1,336	$ 24,957	$ (50)
Interest rate derivatives	(205)	—	(205)	—
Total	$ (9,355)	$ 1,336	$ 24,752	$ (50)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ 7,058	$ (928)	$12,373	$ 9,549
Interest rate derivatives	Interest expense	71	72	142	144
Total		$ 7,129	$ (856)	$12,515	$ 9,693

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ (1,016)	$ —	$ 105	$ —
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ (1,016)	$ —	$ 105	$ —

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 6,417	$ 12,498	$ (967)	$12,498
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ 6,417	$ 12,498	$ (967)	$12,498

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$ (21,295)	$ 5,138	$ 672	$ 56,576
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	—	36,842	—	50,568
Total		$ (21,295)	$ 41,980	$ 672	$ 107,144

We recognized $36.5 million and $27.0 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended June 30, 2010 and 2009, respectively. We recognized $45.2 million and $46.1 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the six months ended June 30, 2010 and 2009, respectively.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty performance.

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

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15. RELATED PARTY TRANSACTIONS:

As discussed in “Recent Developments” in Note 1, Regency became a related party on May 26, 2010. Regency provides us with contract compression services. For the period from May 26, 2010 to June 30, 2010, we recorded costs of products sold of $0.7 million and operating expenses of $0.2 million related to transactions with Regency.

We and subsidiaries of Enterprise transport natural gas on each other’s pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. The following table presents sales to and purchase from affiliates of Enterprise:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Natural Gas Operations:				
Sales	$ 130,526	$ 90,591	$ 275,246	$ 165,074
Purchases	6,936	2,688	13,533	16,346
Propane Operations:				
Sales	481	5,226	10,966	11,508
Purchases	52,415	41,005	218,179	176,223

Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that was extended until March 2015, and includes an option to extend the agreement for an additional year. As of December 31, 2009, Titan had forward mark-to-market derivatives for approximately 6.1 million gallons of propane at a fair value asset of $3.3 million with Enterprise. All of these forward contracts were settled as of June 30, 2010. In addition, as of June 30, 2010 and December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 51.7 million and 20.5 million gallons of propane at a fair value liability of $4.5 million and a fair value asset of $8.4 million, respectively, with Enterprise.

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

	June 30, 2010	December 31, 2009
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$ 41,451	$ 47,005
Propane Operations	181	3,386
Other	7,888	6,978
Total accounts receivable from related parties:	$ 49,520	$ 57,369
Accounts payable from related parties:		
Enterprise:		
Natural Gas Operations	$ 825	$ 3,518
Propane Operations	5,478	31,642
Other	1,320	3,682
Total accounts payable from related parties:	$ 7,623	$ 38,842

The net imbalance payable from Enterprise was $1.9 million and $0.7 million for June 30, 2010 and December 31, 2009, respectively.

16. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	June 30, 2010	December 31, 2009
Deposits paid to vendors	$ 44,393	$ 79,694
Prepaid and other	46,719	68,679
Total other current assets	$ 91,112	$ 148,373

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2010	December 31, 2009
Interest payable	$ 133,314	$ 136,222
Customer advances and deposits	69,591	88,430
Accrued capital expenditures	73,432	46,134
Accrued wages and benefits	40,272	25,202
Taxes other than income taxes	72,041	23,294
Income taxes payable	9,811	3,401
Deferred income taxes	109	—
Other	60,576	42,485
Total accrued and other current liabilities	$ 459,146	$ 365,168

17. REPORTABLE SEGMENTS:

Our financial statements reflect four reportable segments, which conduct their business exclusively in the United States of America, as follows:

- natural gas operations consisting of:
  - intrastate transportation and storage;
  - interstate transportation; and
  - midstream.
- retail propane and other retail propane related operations

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general and administrative expenses. The following tables present the financial information by segment for the following periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 530,174	$ 372,674	$ 1,132,530	$ 828,477
Intersegment revenues	318,713	121,260	582,849	294,108
	848,887	493,934	1,715,379	1,122,585
Interstate transportation – revenues from external customers	70,079	70,585	138,348	131,934
Midstream:				
Revenues from external customers	407,123	504,973	1,025,830	1,099,776
Intersegment revenues	350,671	40,795	528,735	77,624
	757,794	545,768	1,554,565	1,177,400
Retail propane and other retail propane related – revenues from external customers	220,126	202,272	781,281	718,184
All other:				
Revenues from external customers	40,204	1,313	61,698	3,546
Intersegment revenues	935	—	2,381	—
	41,139	1,313	64,079	3,546
Eliminations – against operating expenses	(84)	—	(168)	—
Eliminations – against cost of products sold	(670,235)	(162,055)	(1,113,797)	(371,732)
Total revenues	$ 1,267,706	$ 1,151,817	$ 3,139,687	$ 2,781,917
Cost of products sold:				
Intrastate transportation and storage	$ 629,185	$ 233,951	$ 1,270,691	$ 616,565
Midstream	662,564	470,108	1,362,356	1,029,284
Retail propane and other retail propane related	115,133	82,886	424,890	307,991
All other	34,210	1,103	51,582	3,024
Eliminations	(670,235)	(162,055)	(1,113,797)	(371,732)
Total cost of products sold	$ 770,857	$ 625,993	$ 1,995,722	$ 1,585,132
Depreciation and amortization:				
Intrastate transportation and storage	$ 29,152	$ 25,859	$ 58,144	$ 50,892
Interstate transportation	12,762	12,837	25,213	23,496
Midstream	20,282	17,191	40,617	33,701
Retail propane and other retail propane related	20,297	20,174	40,385	40,446
All other	1,384	113	2,794	242
Total depreciation and amortization	$ 83,877	$ 76,174	$ 167,153	$ 148,777

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating income (loss):				
Intrastate transportation and storage	$ 127,818	$ 156,929	$ 262,022	$ 300,644
Interstate transportation	32,165	31,950	63,762	60,145
Midstream	49,865	28,050	102,197	53,189
Retail propane and other retail propane related	(6,436)	4,560	120,338	168,629
All other	(231)	(1,016)	(1,362)	(1,782)
Selling, general and administrative expenses not allocated to segments	(3,997)	(1,253)	(3,435)	(752)
Total operating income	$ 199,184	$ 219,220	$ 543,522	$ 580,073
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (103,014)	$ (100,680)	$ (207,976)	$ (182,725)
Equity in earnings of affiliates	4,072	1,673	10,253	2,170
Gains (losses) on disposal of assets	1,385	181	(479)	(245)
Gains on non-hedged interest rate derivatives	—	36,842	—	50,568
Allowance for equity funds used during construction	4,298	(1,839)	5,607	18,588
Impairment of investment in affiliate	(52,620)	—	(52,620)	—
Other income, net	(5,893)	(100)	(4,860)	967
Income tax expense	(4,569)	(4,559)	(10,493)	(11,491)
	(156,341)	(68,482)	(260,568)	(122,168)
Net income	$ 42,843	$ 150,738	$ 282,954	$ 457,905

	As of June 30, 2010	As of December 31, 2009
Total assets:		
Intrastate transportation and storage	$ 4,839,267	$ 4,901,102
Interstate transportation	2,966,334	3,313,837
Midstream	1,644,369	1,523,538
Retail propane and other retail propane related	1,681,801	1,784,353
All other	224,319	212,142
Total	$ 11,356,090	$ 11,734,972

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 46,104	$ 306,096
Interstate transportation	428,978	63,955
Midstream	188,246	54,610
Retail propane and other retail propane related	30,404	33,228
All other	4,426	3,003
Total	$ 698,158	$ 460,892

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

(Tabular dollar amounts are in thousands)

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 24, 2010. Our Management's Discussion and Analysis 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 "Item 1A. Risk Factors" included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2009.

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

Overview

Our activities are primarily conducted through our operating subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company ("ETC OLP"); Energy Transfer Interstate Holdings, LLC ("ET Interstate"), the parent company of Transwestern Pipeline Company, LLC ("Transwestern"), ETC Fayetteville Express Pipeline, LLC ("ETC FEP"), and ETC Tiger Pipeline, LLC ("ETC Tiger"); ETC Compression, LLC ("ETC Compression"), Heritage Operating, L.P. ("HOLP"); and Titan Energy Partners, L.P. ("Titan").

General

Our primary objective is to increase the level of our cash distributions over time by pursuing a business strategy that is currently focused on growing our natural gas midstream and intrastate transportation and storage businesses (including transportation, gathering, compression, treating, processing, storage and marketing) and our propane business through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain additional businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

During the past several years, we have been successful in completing several transactions that have been accretive to our Unitholders. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional cash flow to our Unitholders for years to come.

Our principal operations are conducted in the following segments:

- Intrastate transportation and storage — Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are receipt points between West Texas to East Texas. When basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and/or fuel retention. Excess fuel retained after consumption is sold at market prices. In addition to transport fees, our HPL System generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies.

  We generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we utilize any excess storage capacity to inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment 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 and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial 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. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains.

We also use financial derivatives to hedge prices on a portion of natural gas volumes retained as fees in our intrastate transportation and storage segment. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income 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.

In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's open capacity. Gains and losses on these financial derivatives are dependent on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings.

- Interstate transportation — Revenue is primarily generated by fees earned from natural gas transportation services and operational gas sales.

- Midstream — Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

In addition to fee-based contracts for gathering, treating and processing, we also have percent of proceeds and keep-whole contracts, which are subject to market pricing. For percent of proceeds contracts (which accounted for approximately 11% and 12% of total processed volumes for the six month periods ending June 30, 2010 and 2009, respectively), we retain a portion of the natural gas and NGLs processed as a fee. When natural gas and NGL pricing increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGL's decrease, so does the value of the portion we retain as a fee. For keep-whole contracts (which accounted for approximately 32% and 26% of total processed volumes for the six month periods ending June 30, 2010 and 2009, respectively), we retain the difference between the price of NGLs and the cost of the gas to process it. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could be negative. In the event it is uneconomical to process this gas, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs.

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

- Retail propane and other retail propane related operations - Revenue is principally generated from the sale of propane and propane-related products and services.

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Results of Operations

Consolidated Results

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Change	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Change
Revenues	$ 1,267,706	$ 1,151,817	$ 115,889	$ 3,139,687	$ 2,781,917	$ 357,770
Cost of products sold	770,857	625,993	144,864	1,995,722	1,585,132	410,590
Gross margin	496,849	525,824	(28,975)	1,143,965	1,196,785	(52,820)
Operating expenses	169,533	176,681	(7,148)	340,281	358,454	(18,173)
Depreciation and amortization	83,877	76,174	7,703	167,153	148,777	18,376
Selling, general and administrative	44,255	53,749	(9,494)	93,009	109,481	(16,472)
Operating income	199,184	219,220	(20,036)	543,522	580,073	(36,551)
Interest expense, net of interest capitalized	(103,014)	(100,680)	(2,334)	(207,976)	(182,725)	(25,251)
Equity in earnings of affiliates	4,072	1,673	2,399	10,253	2,170	8,083
Gains (losses) on disposal of assets	1,385	181	1,204	(479)	(245)	(234)
Gains on non-hedged interest rate derivatives	—	36,842	(36,842)	—	50,568	(50,568)
Allowance for equity funds used during construction	4,298	(1,839)	6,137	5,607	18,588	(12,981)
Impairment of investment in affiliate	(52,620)	—	(52,620)	(52,620)	—	(52,620)
Other, net	(5,893)	(100)	(5,793)	(4,860)	967	(5,827)
Income tax expense	(4,569)	(4,559)	(10)	(10,493)	(11,491)	998
Net income	$ 42,843	$ 150,738	$(107,895)	$ 282,954	$ 457,905	$(174,951)

See the detailed discussion of revenues, costs of products sold, gross margin, operating expenses, and depreciation and amortization by operating segment below.

Interest Expense. Interest expense increased $2.3 million for the three months ended June 30, 2010 and $25.3 million for the six months ended June 30, 2010 compared to the same periods in the previous year principally due to our issuances of $1.0 billion in senior notes in April 2009 and Transwestern's issuance of $350.0 million of senior notes in December 2009. Interest expense is presented net of capitalized interest and allowance for debt funds used during construction, which totaled $2.9 million and $3.9 million for the three months ended June 30, 2010 and 2009, respectively, and $3.9 million and $9.8 million for the six months ended June 30, 2010 and 2009, respectively.

Equity in Earnings of Affiliates. The equity in earnings of affiliates increased $2.4 million for the three months ended June 30, 2010 and $8.1 million for the six months ended June 30, 2010 compared to the same periods in the previous year primarily attributable to increased earnings of MEP as a result of placing the Midcontinent Express Pipeline into service in 2009 (the first Zone in April 2009 and the second Zone in August 2009). On May 26, 2010, we transferred substantially all of our interest in MEP to ETE. We recorded equity in earnings related to MEP of $3.4 million and $8.9 million for the three and six months ended June 30, 2010, respectively, compared to equity in earnings related to MEP of $0.7 million for the three and six months ended June 30, 2009.

Gains on Non-Hedged Interest Rate Derivatives. The gains on non-hedged interest rate derivatives decreased $36.8 million for the three months ended June 30, 2010 and $50.6 million for the six months ended June 30, 2010 compared to the same periods in the previous year. During 2009, we settled all of our non-hedged interest rate swaps. As of June 30, 2010, we had no outstanding non-hedged interest rate swaps.

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction (AFUDC) increased $6.1 million for the three months ended June 30, 2010, primarily due to construction on the Tiger pipeline and decreased $13.0 million for the six months ended June 30, 2010 compared to the same periods in the previous year, primarily due to Transwestern's completion of the Phoenix lateral pipeline in February 2009. AFUDC on equity amounts recorded in property, plant and equipment (excluding AFUDC gross-up) were $4.2 million and ($1.1) million for the three months ended June 30, 2010 and 2009, respectively and $5.5 million and $11.4 million for the six months ended June 30, 2010 and 2009.

Impairment of Investment in Affiliate. In conjunction with the transfer of our interest in MEP, we recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest to its estimated fair value.

Segment Operating Results

We evaluate segment performance based on operating income (either in total or by individual segment), 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.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 24, 2010.

Operating income (loss) by segment is as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Intrastate transportation and storage	$ 127,818	$ 156,929	$ (29,111)	$ 262,022	$ 300,644	$ (38,622)
Interstate transportation	32,165	31,950	215	63,762	60,145	3,617
Midstream	49,865	28,050	21,815	102,197	53,189	49,008
Retail propane and other retail propane related	(6,436)	4,560	(10,996)	120,338	168,629	(48,291)
All other	(231)	(1,016)	785	(1,362)	(1,782)	420
Selling, general and administrative expenses not allocated to segments	(3,997)	(1,253)	(2,744)	(3,435)	(752)	(2,683)
Operating income	$ 199,184	$ 219,220	$ (20,036)	$ 543,522	$ 580,073	$ (36,551)

Selling, General and Administrative Expenses Not Allocated to Segments. Selling, general and administrative expenses are allocated monthly to the Operating Companies using the Modified Massachusetts Formula Calculation ("MMFC"). The expenses subject to allocation are based on estimated amounts and take into consideration our actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month, which results in over or under allocation of these costs due to timing differences.

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Natural gas MMBtu/d — transported	11,769,582	13,593,471	(1,823,889)	11,563,460	13,611,768	(2,048,308)
Natural gas MMBtu/d — sold	1,666,614	812,193	854,421	1,556,487	876,506	679,981
Revenues	$ 848,887	$ 493,934	$ 354,953	$ 1,715,379	$ 1,122,585	$ 592,794
Cost of products sold	629,185	233,951	395,234	1,270,691	616,565	654,126
Gross margin	219,702	259,983	(40,281)	444,688	506,020	(61,332)
Operating expenses	47,369	56,918	(9,549)	89,330	110,408	(21,078)
Depreciation and amortization	29,152	25,859	3,293	58,144	50,892	7,252
Selling, general and administrative	15,363	20,277	(4,914)	35,192	44,076	(8,884)
Segment operating income	$ 127,818	$ 156,929	$ (29,111)	$ 262,022	$ 300,644	$ (38,622)

Volumes. We experienced a decrease in volumes transported on our intrastate transportation systems during both the three and six months ended June 30, 2010 due to less production by our customers in areas where our assets are located and by less favorable basis differentials principally between the West and East Texas market hubs. The average spot price difference between these locations was $0.12/MMBtu during the three months ended June 30, 2010 compared to $0.45/MMBtu during the three months ended June 30, 2009 and $0.08/MMBtu during the six months ended June 30, 2010 compared to $0.54/MMBtu during the six months ended June 30, 2009.

The increase in natural gas sold during both the three and six months ended June 30, 2010 was a result of more activity by our commercial group to optimize our transportation pipeline assets.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Transportation fees	$ 154,754	$ 178,971	$(24,217)	$ 295,552	$ 354,104	$(58,552)
Natural gas sales and other	15,950	19,247	(3,297)	55,960	37,950	18,010
Retained fuel revenues	37,385	35,552	1,833	73,087	70,729	2,358
Storage margin, including fees	11,613	26,213	(14,600)	20,089	43,237	(23,148)
Total gross margin	$ 219,702	$ 259,983	$(40,281)	$ 444,688	$ 506,020	$(61,332)

Intrastate transportation and storage gross margin decreased primarily due to the following factors:

- Transportation fees decreased during both the three and six months ended June 30, 2010 as a result of the volume decreases discussed above.
- Changes in margin from natural gas sales and other activity were primarily due to the impacts from system optimization activities. Excluding the derivatives related to storage, we recognized unrealized losses during the three and six months ended June 30, 2010 of $21.8 million and $16.9 million, respectively, compared to unrealized gains during the three and six months ended June 30, 2009 of $0.6 million and $3.2 million, respectively.
- Although our transported volumes were down and we retained less natural gas, our retention revenue increased during both the three and six months ended June 30, 2010 by $1.8 million and $2.4 million, respectively, principally due to more favorable pricing. Our average retention price, excluding the effects of hedging activity (which is included in our "Natural gas sales and other" margin), during the three and six months ended June 30, 2010 was $4.48/MMBtu and $4.45/MMBtu, respectively, compared to $3.26/MMBtu and $3.29/MMBtu for the three and six months ended June 30, 2009, respectively.

Storage margin was comprised of the following:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Withdrawals from storage natural gas inventory (MMBtu)	871,203	—	871,203	27,887,990	11,254,403	16,633,587
Margin on physical sales	$ 1,274	$ 150	$ 1,124	$ 65,652	$ (11,016)	$ 76,668
Fair value adjustments	6,301	15,063	(8,762)	(62,254)	(29,559)	(32,695)
Settlements of financial derivatives	1,570	(6,532)	8,102	(8,929)	159,714	(168,643)
Unrealized gains (losses) on derivatives	(7,824)	10,189	(18,013)	5,294	(89,718)	95,012
Net impact of natural gas inventory transactions	1,321	18,870	(17,549)	(237)	29,421	(29,658)
Revenues from fee-based storage	10,328	9,763	565	21,627	18,106	3,521
Other costs	(36)	(2,420)	2,384	(1,301)	(4,290)	2,989
Total storage margin	$ 11,613	$ 26,213	$ (14,600)	$ 20,089	$ 43,237	$ (23,148)

For the three months ended June 30, 2010, storage margin decreased by $14.6 million primarily due to a minimal change in the price difference between the spot price and the forward price during the current period as compared to the prior year.

For the six months ended June 30, 2010, storage margin decreased by $23.1 million primarily due to less price variance between the carrying cost of our inventory and the locked-in sales price of our financial derivative. We began applying fair value hedge accounting to the natural gas we purchase for storage and adjust the carrying amount of our inventory to the spot price on April 1, 2009. The margin that we realized for the natural gas withdrawn during the six months ended June 30, 2010 had been previously recognized through fair value adjustments and was therefore not reflected in the period of the actual withdrawals. We applied mark to market accounting prior to April 1, 2009; therefore, the storage margin for the six months ended June 30, 2009 reflected the recognition of gains on derivatives.

Operating Expenses. Intrastate operating expenses decreased for the three and six months ended June 30, 2010, principally due to decreases in consumption expense of $4.7 million and $12.6 million, respectively. Additionally, we experienced a decrease in ad valorem expenses of $2.1 million, and lower electricity expense of $2.1 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009.

For the six months ended June 30, 2010, we experienced a decrease in ad valorem expenses of $3.5 million, lower electricity expense of $3.2 million, and lower compressor maintenance expense of $1.5 million as compared to the six months ended June 30, 2009. The remaining decrease was a result of lower overhead costs incurred.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased during the three and six months ended June 30, 2010 compared to the prior periods primarily due to the completion of pipeline projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative. Intrastate selling, general and administrative expenses decreased for the three and six months ended June 30, 2010 as a result of decreases in professional fees of $4.6 million and $11.0 million, respectively. For the six months ended June 30, 2010, the decrease in professional fees was offset by an increase in employee-related costs (including allocated overhead) of $2.5 million compared to the six months ended June 30, 2009.

Interstate Transportation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Natural gas MMBtu/d – transported	1,508,739	1,683,298	(174,559)	1,533,194	1,715,252	(182,058)
Natural gas MMBtu/d – sold	24,708	24,294	414	22,388	19,695	2,693
Revenues	$ 70,079	$ 70,585	$ (506)	$ 138,348	$ 131,934	$ 6,414
Operating expenses	20,200	17,344	2,856	36,261	32,709	3,552
Depreciation and amortization	12,762	12,837	(75)	25,213	23,496	1,717
Selling, general and administrative	4,952	8,454	(3,502)	13,112	15,584	(2,472)
Segment operating income	$ 32,165	$ 31,950	$ 215	$ 63,762	$ 60,145	$ 3,617

The interstate transportation segment data presented above does not include our interstate pipeline joint ventures, for which we reflect our proportionate share of income within “Equity in earnings of affiliates” below operating income in our condensed consolidated statement of operations. We recorded equity in earnings related to MEP of $3.4 million and $0.7 million for the three months ended June 30, 2010 and 2009, and $8.9 million and $0.7 million for the six months ended June 30, 2010 and 2009, respectively, related to our 50% joint venture investment. As discussed above, we transferred substantially all of our interest in MEP to ETE on May 26, 2010.

Volumes. Transported volumes decreased during the three and six months ended June 30, 2010 primarily due to less favorable market conditions for transporting natural gas principally from the San Juan Basin to East delivery points.

Revenues. For the three months ended June 30, 2010, revenues decreased by approximately $0.5 million compared to the three months ended June 30, 2009 primarily as a result of less favorable market conditions for transporting natural gas from the San Juan to East delivery points during the period.

For the six months ended June 30, 2010, revenues increased by approximately $6.4 million compared to the prior period primarily due to increases in margin related to our operational gas sales, in addition to the completion of the Phoenix project in February 2009. This increase was partially offset by a decrease in transportation revenues due to lower transported volumes compared to the six months ended June 30, 2009.

Operating Expenses. Operating expenses increased during the three and six months ended June 30, 2010 primarily due to increases in ad valorem taxes resulting from increased property values related to the Phoenix pipeline. This increase was partially offset by a net decrease in other operating expenses primarily due to lower electric demand costs resulting from lower throughput.

Depreciation and Amortization. Depreciation and amortization expense increased during the six months ended June 30, 2010, primarily due to incremental depreciation associated with the completion of the Phoenix pipeline expansion that was completed in February 2009.

Selling, General and Administrative. Selling, general and administrative expenses decreased during the three and six months ended June 30, 2010 primarily due to lower employee-related costs and allocated overhead.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Natural gas sold (MMBtu/d)	412,195	916,048	(503,853)	554,131	1,003,236	(449,105)
NGLs produced (Bbls/d)	51,140	48,219	2,921	49,734	47,404	2,330
Revenues	$ 757,794	$ 545,768	$ 212,026	$ 1,554,565	$ 1,177,400	$ 377,165
Cost of products sold	662,564	470,108	192,456	1,362,356	1,029,284	333,072
Gross margin	95,230	75,660	19,570	192,209	148,116	44,093
Operating expenses	19,033	17,011	2,022	36,863	34,804	2,059
Depreciation and amortization	20,282	17,191	3,091	40,617	33,701	6,916
Selling, general and administrative	6,050	13,408	(7,358)	12,532	26,422	(13,890)
Segment operating income	$ 49,865	$ 28,050	$ 21,815	$ 102,197	$ 53,189	$ 49,008

Volumes. NGL production increased during the three and six months ended June 30, 2010 primarily due to increased inlet volumes at our Godley plant as a result of favorable NGL prices and more production by our customers in the North Texas area. The decrease in natural gas sold during the period primarily reflects decreased marketing activities resulting from less favorable market conditions.

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

Gross Margin.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Gathering and processing fee-based revenues	$ 55,583	$ 45,976	$ 9,607	$ 109,878	$ 93,884	$ 15,994
Non fee-based contracts and processing	50,226	32,164	18,062	97,496	49,370	48,126
Other	(10,579)	(2,480)	(8,099)	(15,165)	4,862	(20,027)
Total gross margin	$ 95,230	$ 75,660	$19,570	$ 192,209	$ 148,116	$ 44,093

Gathering and processing fee-based revenues increased between the periods due to the following:

- For the three months ended June 30, 2010, an increase in gathering and processing volumes resulted in an increase of approximately $3.8 million in fee-based revenues compared to the three months ended June 30, 2009. Additionally, increased volumes resulting from our recent acquisitions and other growth capital expenditures located in Louisiana provided an increase in our fee-based margin of $5.8 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009.
- For the six months ended June 30, 2010, an increase in gathering and processing volumes accounted for approximately $3.8 million of the total increase in fee-based revenues compared to the six months ended June 30, 2009. In addition, increased volumes resulting from our recent acquisitions and other growth capital expenditures located in Louisiana provided an increase in our fee-based margin of $12.2 million.

Non fee-based contracts and processing margins increased between the periods due to the following:

- For the three months ended June 30, 2010, our non fee-based gross margins increased primarily due to higher processing volumes at our Godley plant and more favorable NGL prices. The composite NGL price increased to $0.98 per gallon for the three months ended June 30, 2010 from $0.69 per gallon during the three months ended June 30, 2009. The increase in NGL volumes, as well as more favorable pricing, resulted in an increase in our non fee-based margin of $18.1 million.
- For the six months ended June 30, 2010, non fee-based gross margin increased primarily due to higher processing volumes at our Godley plant and more favorable NGL prices. The composite NGL price increased to $1.04 per gallon from $0.64 per gallon in the prior comparable period. The increase in NGL volumes, as well as more favorable pricing, resulted in an increase in our non fee-based margin of $48.1 million.

Other midstream gross margin reflects the following:

- For the three months ended June 30, 2010, the decrease in other midstream gross margin resulted from losses of $10.6 million from marketing activities due to less favorable market conditions compared to the three months ended June 30, 2009. During the three months ended June 30, 2010, our midstream segment realized derivative gains that had previously been recorded through mark to market adjustments. Therefore, the costs during the period did not have an offset as the unrealized gains were recognized in a prior period. We recorded unrealized losses of $8.7 million during the three months ended June 30, 2010 compared to unrealized gains of $5.8 million during the three months ended June 30, 2009.
- For the six months ended June 30, 2010, the decrease in other midstream gross margin resulted from losses of $15.2 million from marketing activities due to less favorable market conditions compared to the six months ended June 30, 2009. We recorded unrealized losses of $11.7 million during the six months ended June 30, 2010 compared to unrealized losses of $5.4 million during the six months ended June 30, 2009.

Operating Expenses. Operating expenses increased between the periods primarily as a result of increases in maintenance costs and other various operating costs as a result of the increased activity noted above.

Depreciation and Amortization. Midstream depreciation and amortization expense increased between the periods primarily due to incremental depreciation from the continued expansion of our Louisiana assets.

Selling, General and Administrative. For the three months ended June 30, 2010, midstream selling, general and administrative expenses decreased compared to the three months ended June 30, 2009 primarily due to a decrease in professional fees of $6.6 million and a net decrease in all other general and administrative costs of $0.7 million.

For the six months ended June 30, 2010, midstream selling, general and administrative expenses decreased compared to the six months ended June 30, 2009 primarily due to a decrease in professional fees of $8.9 million, employee-related costs (including allocated overhead expenses) of approximately $4.2 million and a net decrease in all other general and administrative costs of $0.7 million.

Retail Propane and Other Retail Propane Related

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Retail propane gallons (in thousands)	84,973	92,153	(7,180)	302,584	310,633	(8,049)
Retail propane revenues	$ 197,147	$ 179,770	$ 17,377	$ 730,586	$ 667,677	$ 62,909
Other retail propane related revenues	22,979	22,502	477	50,695	50,507	188
Retail propane cost of products sold	110,282	78,070	32,212	415,263	298,292	116,971
Other retail propane related cost of products sold	4,851	4,816	35	9,627	9,699	(72)
Gross margin	104,993	119,386	(14,393)	356,391	410,193	(53,802)
Operating expenses	79,970	84,294	(4,324)	171,702	178,470	(6,768)
Depreciation and amortization	20,297	20,174	123	40,385	40,446	(61)
Selling, general and administrative	11,162	10,358	804	23,966	22,648	1,318
Segment operating income	$ (6,436)	$ 4,560	$ (10,996)	$ 120,338	$ 168,629	$ (48,291)

Volumes. For the three months ended June 30, 2010, retail propane volumes decreased approximately 7.8% due to the lingering effects of customer conservation and the continued impact of the economic recession. Volumes were only slightly impacted by weather, which was approximately 1.0% warmer than normal as compared to weather that approximated normal during the same period in 2009. Average temperatures in our service areas are based on 10 year heating degree day data.

For the six months ended June 30, 2010, weather in our operating areas was approximately 4.1% colder than normal as compared to weather which was approximately 1.9% colder than normal during the same period in 2009. Despite the challenges of the lingering effects of customer conservation and the impact of the economic recession, retail propane volumes decreased only slightly by approximately 2.6%.

Gross Margin. For the three months ended June 30, 2010, gross margin decreased $14.4 million primarily due to the impact of mark to market accounting of financial instruments in 2009 and to a lesser degree due to the decline in volumes during the current period. Prior to April 2009, our financial instruments used to hedge our customer prebuy programs were not designated as cash flow hedges for accounting purposes, and changes in market value were recorded in cost of products sold in the condensed consolidated statements of operations. Unrealized gains of $7.8 million were recorded during the three month period ended June 30, 2009 on these contracts. Substantially all of these financial instruments were settled as of March 31, 2010 and so there was no mark to market impact for the three month period ended June 30, 2010. Excluding the impact of the mark to market accounting during 2009, the average gross margin per gallon sold was relatively consistent period over period.

For the six months ended June 30, 2010, gross margin decreased $53.8 million primarily due to the impact of the mark to market accounting of financial instruments in 2009 and a slight decrease due to the decline in volumes during the current period. Prior to April 2009, our financial instruments used to hedge our customer prebuy programs were not designated as cash flow hedges for accounting purposes, and changes in market value were recorded in cost of products sold in the condensed consolidated statements of operations. The propane margins were positively impacted in the 2009 period by the recognition of unrealized gains of $43.2 million during the period ended June 30, 2009 on these contracts. In comparison, the impact of the remaining contracts under mark to market accounting was unrealized losses for the six month period ended June 30, 2010 of $3.3 million. Excluding the impact of the mark to market accounting during 2009, the average gross margin per gallon sold was relatively consistent period over period.

Operating Expenses. Operating expenses decreased during the three and six months ended June 30, 2010 primarily due to decreases of $6.1 million and $10.8 million, respectively, in employee wages and benefits due to lower seasonal staffing needs and performance bonus accruals. These decreases were partially offset by a slight increase in other general operating expenses primarily in our vehicle fuel expenses due to the increase in fuel costs between periods.

Liquidity and Capital Resources

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

We currently believe that our business has the following future capital requirements:

- growth capital expenditures for our midstream and intrastate transportation and storage segments, primarily for the construction of new pipelines and compression, for which we expect to spend between $200 million and $220 million for the remainder of 2010;
- growth capital expenditures for our interstate transportation segment, excluding capital contributions to our joint ventures as discussed below, for the construction of new pipelines for which we expect to spend between $550 million and $610 million for the remainder of 2010;
- growth capital expenditures for our retail propane segment of between $15 million and $25 million for the remainder of 2010; and
- maintenance capital expenditures of between $40 million and $55 million for the remainder of 2010, which include (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; and (iii) capital expenditures for our propane operations to extend the useful lives of our existing propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet.

In addition to the capital expenditures noted above, we expect that capital contributions to the joint ventures that we currently have interests in will be between $20 million and $30 million for the remainder of 2010.

In addition, we may enter into acquisitions, including the potential acquisition of new pipeline systems and propane operations.

We generally fund our capital requirements with cash flows from operating activities and, to the extent that they exceed cash flows from operating activities, with proceeds of borrowings under existing credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof.

We raised approximately $423.6 million in net proceeds from our Common Unit offering in January 2010. In addition, we raised $151.0 million in net proceeds during the six months ended June 30, 2010 under our Equity Distribution Agreement, as described in Note 11 to our condensed consolidated financial statements. As of June 30, 2010, in addition to approximately $78.8 million of cash on hand, we had available capacity under our revolving credit facility (the "ETP Credit Facility") of approximately $1.95 billion. Based on our current estimates, we expect to utilize these resources, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2010; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

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 factors 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 executive 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 result from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have 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 propane and natural gas inventories, and the timing of advances and deposits received from customers.

Six months ended June 30, 2010 compared to six months ended June 30, 2009. Cash provided by operating activities during 2010 was $884.0 million as compared to $702.7 million for 2009. Net income was $283.0 million and $457.9 million for 2010 and 2009, respectively. The difference between net income and the net cash provided by operating activities primarily consisted of non-cash items totaling $255.9 million and $161.1 million and changes in operating assets and liabilities of $332.0 million and $85.0 million for 2010 and 2009, respectively.

The non-cash activity in 2010 and 2009 consisted primarily of depreciation and amortization of $167.2 million and $148.8 million, respectively. In addition, non-cash compensation expense was $15.2 million and $15.1 million for 2010 and 2009, respectively. We also received distributions from our affiliates during 2010 that exceeded our equity in earnings by $20.4 million. These amounts are partially offset by the allowance for equity funds used during construction of $5.6 million and $18.6 million for 2010 and 2009, respectively.

Investing Activities

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

Six months ended June 30, 2010 compared to six months ended June 30, 2009. Cash used in investing activities during 2010 was $750.4 million as compared to $875.5 million for 2009. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2010 were $608.5 million including changes in accruals of $36.3 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2009 of $512.5 million, including changes in accruals of $66.0 million. In addition, in 2010 we paid cash for acquisitions of $153.4 million and made advances to our joint ventures of $5.6 million. We paid cash for acquisitions of $6.4 million and made advances to our joint ventures of $364.0 million ($333.0 million to MEP and $31.0 million to FEP) during 2009.

Growth capital expenditures for 2010, before changes in accruals, were $171.6 million for our midstream and intrastate transportation and storage segments, $413.6 million for our interstate transportation segment, and $15.7 million for our retail propane segment and all other. We also incurred $43.9 million of maintenance capital expenditures, of which $15.6 million related to our midstream and intrastate transportation and storage segments, $11.7 million related to our interstate segment and $16.6 million related to our retail propane segment and all other.

Growth capital expenditures for 2009, before changes in accruals, were $330.7 million for our midstream and intrastate transportation and storage segments, $46.8 million for our interstate transportation segment, and $24.7 million for our retail propane segment and all other. We also incurred $44.3 million in maintenance expenditures, of which $27.8 million related to our midstream and intrastate transportation and storage segments, $5.8 million related to our interstate segment and $10.7 million related to our retail propane segment.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, as discussed below under “Financing and Sources of Liquidity,” 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, as discussed below under “Cash Distributions.”

Six months ended June 30, 2010 compared to six months ended June 30, 2009. Cash provided by financing activities during 2010 was $123.0 million as compared to cash received from financing activities of $195.2 million for 2009. In 2010, we received $574.5 million in net proceeds from Common Unit offerings, including $151.0 million under our

Equity Distribution program, as compared to net proceeds from Common Unit offerings of $578.9 million in 2009 (see Note 11 to our condensed consolidated financial statements). Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint ventures, as well as for general partnership purposes. During 2010, we had a net decrease in our debt level of $144.5 million as compared to a net increase of $86.5 million for 2009. In addition, we paid distributions of $538.6 million to our partners in 2010 as compared to $465.8 million in 2009.

Financing and Sources of Liquidity

In January 2010, we issued 9,775,000 Common Units through a public offering and net proceeds of $423.6 million from the offering were used primarily to repay borrowings under our revolving credit facility and to fund capital expenditures related to pipeline projects.

During the six months ended June 30, 2010, we issued 3,340,783 of our Common Units pursuant to our Equity Distribution Agreement. The proceeds of approximately $151.0 million, net of commissions, were used for general partnership purposes. In addition, we initiated trades on 501,500 of our Common Units that had not settled as of June 30, 2010. Approximately $40.6 million remains available to be issued under the agreement based on trades initiated through June 30, 2010.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 2010	December 31, 2009
ETP Senior Notes	$5,050,000	$ 5,050,000
Transwestern Senior Unsecured Notes	870,000	870,000
HOLP Senior Secured Notes	127,785	140,512
Revolving credit facilities	29,256	160,000
Other long-term debt	9,176	10,122
Unamortized discounts	(12,458)	(12,829)
Fair value adjustments related to interest rate swaps	16,377	—
Total debt	$6,090,136	$ 6,217,805

The terms of our consolidated indebtedness are described in more detail in our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 24, 2010.

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity) under the credit agreement that governs the ETP Credit Facility. The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of June 30, 2010, there was $29.3 million of borrowings outstanding under the ETP Credit Facility. Taking into account letters of credit of approximately $21.8 million, the amount available for future borrowings was $1.95 billion.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the “HOLP Credit Facility”) available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility. At June 30, 2010, there was no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of June 30, 2010 was $74.5 million.

Other

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the "MEP Facility"), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although we transferred substantially all of our interest in MEP on May 26, 2010 in connection with the Regency Transactions, we will continue to guarantee 50% of MEP's obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify us for any costs related to the guaranty of payments under this facility.

Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP's ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of June 30, 2010, MEP had $33.1 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility, respectively. Our contingent obligations with respect to our 50% guarantee of MEP's outstanding borrowings and letters of credit were $16.6 million and $16.6 million, respectively, as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 1.4%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the "FEP Facility"). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of June 30, 2010, FEP had $663.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP's outstanding borrowings was $331.5 million as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 3.2%.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at June 30, 2010.

Cash Distributions

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

Distributions paid by us are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2009	February 8, 2010	February 15, 2010	$0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at the close of business on August 9, 2010.

The total amounts of distributions declared during the six months ended June 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30,	
	2010	2009
Limited Partners:		
Common Units	$ 332,371	$ 301,738
Class E Units	6,242	6,242
General Partner Interest	9,754	9,720
Incentive Distribution Rights	184,751	168,311
Total distributions declared by ETP	$ 533,118	$ 486,011

New Accounting Standards and Critical Accounting Policies

Disclosure of our critical accounting policies and the impacts of new accounting standards is included in our Annual Report on Form 10-K for the year ended December 31, 2009.

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, 2009, in addition to the interim unaudited condensed consolidated financial statements, 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, 2009. Since December 31, 2009, there have been no material changes to our primary market risk exposures or how those exposures are managed.

The recent adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Part II, Item 1A. Risk Factors of this Form 10-Q.

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Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of June 30, 2010 and December 31, 2009, 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 and gallons for propane. Dollar amounts are presented in thousands.

	June 30, 2010			December 31, 2009		
	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						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(23,182,500)	$ (752)	$ 176	72,325,000	$ 24,554	$ 491
Swing Swaps IFERC	(23,592,500)	1,258	158	(38,935,000)	1,718	2,142
Fixed Swaps/Futures	(395,000)	(11,701)	3	4,852,500	9,949	3,126
Options – Puts	(8,140,000)	13,702	1,255	2,640,000	837	447
Options – Calls	(5,920,000)	(8,314)	636	(2,640,000)	(819)	314
Propane:						
Forwards/Swaps	—	—	—	6,090,000	3,348	785
Fair Value Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(5,410,000)	217	95	(22,625,000)	(4,178)	2
Fixed Swaps/Futures	(18,765,000)	1,087	9,628	(27,300,000)	(13,285)	15,669
Cash Flow Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(10,845,000)	105	172	(13,225,000)	(1,640)	81
Fixed Swaps/Futures	(18,502,500)	11,478	9,115	(22,800,000)	(4,464)	13,197
Options – Puts	25,800,000	5,539	5,161	—	—	—
Options – Calls	(25,800,000)	2,172	2,795	—	—	—
Propane:						
Forwards/Swaps	51,702,000	(4,489)	5,209	20,538,000	8,443	2,609

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information, broker quotes 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 our condensed consolidated results of operations or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of June 30, 2010, we had $29.3 million in variable rate debt outstanding, and we had $350 million of our fixed rate debt swapped to a variable rate using interest rate derivatives. These interest rate derivatives are accounted for as fair value hedges of the fixed rate debt. A hypothetical change of 100 basis points in interest rates would result in a change to interest expense of approximately $3.8 million annually.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

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

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 Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of June 30, 2010 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 and Principal Financial Officers of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended June 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2009 and Note 13 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.

ITEM 1A. RISK FACTORS

Except as disclosed below, there are no material changes from risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2009.

Risks Related to Conflicts of Interest

Our General Partner has conflicts of interest and limited fiduciary responsibilities, which may permit our General Partner to favor its own interests to the detriment of Unitholders.

As of June 30, 2010, ETE owned a limited partner interest in us of approximately 27% and our officers and directors owned approximately 1% of the limited partner interests in us. Our General Partner also controls Regency GP LLC, the ultimate general partner of Regency, which is a publicly traded partnership that competes with us with respect to our natural gas operations. Conflicts of interest could arise in the future as a result of relationships between our General Partner and its affiliates (including Regency GP LLC and its affiliates), on the one hand, and us and our Unitholders, on the other hand. As a result of these conflicts, our General Partner may favor its own interests or those of its affiliates, including Regency, over the interests of our Unitholders. The nature of these conflicts includes the following considerations:

- Remedies are available to Unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.
- Our General Partner is allowed to take into account the interests of parties in addition to us, including Regency GP LLC and its affiliates, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- Our General Partner's affiliates, including Regency GP LLC, Enterprise GP and their affiliates, are not prohibited from engaging in other businesses or activities, including those in direct competition with us.
- Our General Partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings and reserves, each of which can affect the amount of cash that is distributed to Unitholders.
- Our General Partner determines whether to issue additional units or other equity securities of us.
- Our General Partner determines which costs are reimbursable by us.
- Our General Partner controls the enforcement of obligations owed to us by it.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our General Partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- In some instances, our General Partner may borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

Affiliates of our General Partner may compete with us.

Except as provided in our partnership agreement, affiliates and related parties of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Enterprise

GP currently has a 40.6% non-controlling equity interest in LE GP, LLC, ETE's general partner. Additionally, a director of the general partner of Enterprise GP currently serves as a director of LE GP, LLC. Enterprise GP and its subsidiaries own and operate North American midstream energy businesses that compete with us with respect to our natural gas midstream business. On May 26, 2010, our General Partner completed the Regency Transactions and acquired all of the general partner interests in Regency. Regency is a publicly traded partnership that competes with us with respect to our natural gas operations. Additionally, two directors of Regency GP LLC currently serve as directors of LE GP, LLC.

Risks Related to Our Business

We are exposed to claims by third parties related to the claims that were previously brought against us by the FERC.

On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the "Order and Notice") that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC's then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to our trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that we be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against us by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process for potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ's recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against us related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ's fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, we remain a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The plaintiff appealed this determination to the First Court of Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010, the First Circuit Court of Appeals issued an opinion affirming the judgment of the lower court granting ETP's motion for summary judgment. No motion for rehearing was timely filed.

In October 2007, a consolidated class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint. No petition for rehearing was timely filed.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit its own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted our motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obliged to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations and our liquidity.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our transportation, storage, and midstream services.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA recently adopted two sets of regulations addressing greenhouse gas emissions under the Clean Air Act. The first limits emissions of greenhouse gases from motor vehicles beginning with the 2012 model year. EPA has asserted that these final motor vehicle greenhouse gas emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards take effect on January 2, 2011. On June 3, 2010, EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" standards for greenhouse gases that have yet to be developed. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, store, process, or otherwise handle in connection with our services.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. Recently, in April 2010, the EPA proposed to expand its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. If the proposed rule is finalized as proposed, reporting of greenhouse gas emissions from such facilities, including many of our facilities, would be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

In June 2009, the United States House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap on emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain and hold "allowances" corresponding to their annual emissions of greenhouse gases. By steadily reducing the number of available allowances over time, ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Legislation to reduce emissions of greenhouse gases by comparable amounts is currently pending in the United States Senate, and more than one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for our transportation, storage, and midstream services.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our propane and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure its existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(a) *Unregistered Sales of Equity Securities.* Not applicable.

(b) *Use of Proceeds.* Not applicable.

(c) *Issuer Purchases of Equity Securities.* The following table discloses purchases of our Common Units made by us or on our behalf for the three months ended June 30, 2010.

Period	Total Number of Units Purchased (1)	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Yet Be Purchased Under the Plans or Programs
April 1 – April 30	—	$ —	N/A	N/A
May 1 – May 31	1,550	38.95	N/A	N/A
June 1 – June 30	—	—	N/A	N/A
Total	1,550	$ 38.95	N/A	N/A

(1) Pursuant to the terms of our equity incentive plans, to the extent the Partnership is required to withhold federal, state, local or foreign taxes in connection with any grant of an award, the issuance of Common Units upon the vesting of an award, or payment made to a plan participant, it is a condition to the receipt of such payment that the plan participant make arrangements satisfactory to the Partnership for the payment of taxes. A plan participant may relinquish a portion of the Common Units to which the participant is entitled in connection with the issuance of Common Units upon vesting of an award as payment for such taxes. During the three months ended June 30, 2010, certain of the participants in the 2004 Unit Plan and the 2008 Long-Term Incentive Plan elected to have a portion of the Common Units to which they were entitled upon vesting of restricted units withheld by the Partnership to satisfy the Partnership’s tax withholding obligations. None of the Common Units delivered to recipients of unit awards upon vesting were purchased by the Partnership through a publicly announced open-market plan or program.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

(a) Exhibits

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

	Exhibit Number	Description
(8)	2.1	Redemption and Exchange Agreement, dated May 10, 2010, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(1)	3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009.
(2)	3.2	Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(3)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(4)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(6)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(6)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(5)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(7)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(7)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(9)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
(9)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
(9)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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Exhibit Number	Description

* Filed herewith.
** Furnished herewith.

(1) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K filed July 29, 2009.

(2) Incorporated by reference to the same numbered Exhibit to the Registrant's Registration Statement on Form S-1/A, File No. 333-04018, filed June 21, 1996.

(3) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 2000.

(4) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2002.

(5) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 28, 2002.

(6) Incorporated by reference as the same numbered exhibit to the Registrant's Form 10-Q for the quarter ended February 29, 2004.

(7) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007.

(8) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K/A filed June 2, 2010.

(9) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended March 31, 2010.

SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

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

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

Date: August 9, 2010

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

Exhibit 31.1

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

I, Kelcy L. Warren, certify that:

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

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

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

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

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

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: August 9, 2010

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

Exhibit 31.2

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

I, Martin Salinas, Jr., certify that:

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

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

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

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

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

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: August 9, 2010

/s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer

Exhibit 32.1

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

In connection with the quarterly report of Energy Transfer Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kelcy L. Warren, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: August 9, 2010

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Energy Transfer Partners, L.P.

Exhibit 32.2

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

In connection with the quarterly report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Martin Salinas, Jr., Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: August 9, 2010

/s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Energy Transfer Partners, L.P.