Energy Transfer Partners, L.P.
Form 10-Q
August 10, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009

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)

Registrant s telephone number, including area code: (214) 981-0700

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

Indicate by check mark whether the registrant 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 x	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 x

At August 6, 2009, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 168,822,368 Common Units

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FORM 10-Q

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Energy Transfer Partners, L.P. and Subsidiaries

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (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 within the meaning of Section 27A of the Securities Act of 1933 (Securities Act) and Section 21E of the Securities Exchange Act of 1934 (Exchange Act). Statements using words such as anticipate, believe, intend, project, plan, continue, estimate, forecast, may, will, or similar expressions help identify forward-looking statements. Altho 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 every objective will be reached.

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, 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 the Partnership s Report on Form 10-K as of December 31, 2008 filed with the Securities and Exchange Commission (SEC) on March 2, 2009.

Definitions

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

/d	per day
Btu	British thermal unit, an energy measurement
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). 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.
Mcf	thousand cubic feet
MMBtu	million British thermal unit
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.

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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, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 114,229	$ 91,902
Marketable securities	9,630	5,915
Accounts receivable, net of allowance for doubtful accounts	388,324	591,257
Accounts receivable from related companies	37,330	17,895
Inventories	187,654	272,348
Deposits paid to vendors	51,987	78,237
Exchanges receivable	27,596	45,209
Price risk management assets	4,272	5,423
Prepaid expenses and other current assets	54,306	75,215
Total current assets	875,328	1,183,401
PROPERTY, PLANT AND EQUIPMENT, net	8,613,411	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	374,922	10,110
GOODWILL	734,949	743,694
INTANGIBLES AND OTHER ASSETS, net	402,792	394,199
Total assets	$ 11,001,402	$ 10,627,489

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 BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	June 30, 2009	December 31, 2008
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 283,380	$ 381,135
Accounts payable to related companies	7,419	34,547
Exchanges payable	22,793	54,636
Customer advances and deposits	73,031	106,679
Accrued and other current liabilities	273,053	311,988
Price risk management liabilities	1,727	94,978
Interest payable	150,336	106,259
Income taxes payable	4,120	14,538
Deferred income taxes		589
Current maturities of long-term debt	44,382	45,198
Total current liabilities	860,241	1,150,547
LONG-TERM DEBT, less current maturities	5,692,651	5,618,549
DEFERRED INCOME TAXES	110,762	100,597
OTHER NON-CURRENT LIABILITIES	14,571	14,727
COMMITMENTS AND CONTINGENCIES (Note 15)		
	6,678,225	6,884,420
PARTNERS CAPITAL:		
General Partner	169,128	161,159
Limited Partners:		
Common Unitholders (168,786,459 and 152,102,471 units authorized, issued and outstanding at June 30, 2009 and December 31, 2008, respectively)	4,157,171	3,578,997
Class E Unitholders (8,853,832 units authorized, issued and outstanding - held by subsidiary and reported as treasury units)		
Accumulated other comprehensive income (loss)	(3,122)	2,913
Total partners capital	4,323,177	3,743,069
Total liabilities and partners capital	$ 11,001,402	$ 10,627,489

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, 2009	Three Months Ended June 30, 2008 As Adjusted (Note 2)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 As Adjusted (Note 2)
REVENUES:				
Natural gas operations	$ 948,233	$ 2,375,637	$ 2,060,188	$ 4,383,484
Retail propane	179,770	249,449	667,677	847,587
Other	23,814	28,390	54,052	61,776
Total revenues	1,151,817	2,653,476	2,781,917	5,292,847
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	542,004	1,952,569	1,274,117	3,529,837
Cost of products sold - retail propane	78,070	163,962	298,292	556,517
Cost of products sold - other	5,919	7,541	12,723	17,436
Operating expenses	176,681	197,143	358,454	376,113
Depreciation and amortization	76,174	62,421	148,777	121,249
Selling, general and administrative	53,749	44,011	109,481	92,380
Total costs and expenses	932,597	2,427,647	2,201,844	4,693,532
OPERATING INCOME	219,220	225,829	580,073	599,315
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(100,680)	(68,416)	(182,725)	(123,965)
Equity in earnings (losses) of affiliates	1,673	(169)	2,170	(95)
Gains (losses) on disposal of assets	181	515	(245)	(936)
Gains (losses) on non-hedged interest rate derivatives	36,842	355	50,568	(245)
Allowance for equity funds used during construction	(1,839)	15,660	18,588	25,548
Other, net	(100)	1,942	967	10,291
INCOME BEFORE INCOME TAX EXPENSE	155,297	175,716	469,396	509,913
Income tax expense	4,559	10,042	11,491	15,904
NET INCOME	150,738	165,674	457,905	494,009
GENERAL PARTNER S INTEREST IN NET INCOME	87,179	78,983	177,469	153,347
LIMITED PARTNERS INTEREST IN NET INCOME	$ 63,559	$ 86,691	$ 280,436	$ 340,662

BASIC NET INCOME PER LIMITED PARTNER UNIT	$	0.38	$	0.61	$	1.72	$	2.39
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING		166,596,074		142,827,051		161,829,139		142,794,658
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$	0.38	$	0.60	$	1.72	$	2.38
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING		167,197,121		143,353,304		162,384,831		143,323,778

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 COMPREHENSIVE INCOME

(Dollars in thousands)

(unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net income	$ 150,738	$ 165,674	$ 457,905	$ 494,009
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	856	9,482	(9,693)	(13,209)
Change in value of derivative instruments accounted for as cash flow hedges	1,336	(1,273)	(50)	(7,494)
Change in value of available-for-sale securities	3,657	3,110	3,708	2,943
	5,849	11,319	(6,035)	(17,760)
Comprehensive income	$ 156,587	$ 176,993	$ 451,870	$ 476,249

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 STATEMENT OF PARTNERS CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2009

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2008	$ 161,159	$ 3,578,997	$ 2,913	$ 3,743,069
Distributions to partners	(172,866)	(292,961)		(465,827)
Issuance of units in public offerings		578,924		578,924
Capital contributions from General Partner	12,286			12,286
Contributions receivable from General Partner	(8,932)			(8,932)
Distributions on unvested unit awards		(1,387)		(1,387)
Tax effect of remedial income allocation from tax amortization of goodwill		(1,881)		(1,881)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings		14,430		14,430
Non-cash executive compensation expense	12	613		625
Other comprehensive loss, net of tax			(6,035)	(6,035)
Net income	177,469	280,436		457,905
Balance, June 30, 2009	$ 169,128	$ 4,157,171	$ (3,122)	$ 4,323,177

The accompanying notes are an integral part of this condensed consolidated financial statement.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Six Months Ended June 30, 2009	2008
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 702,680	$ 763,963
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(6,362)	(56,786)
Capital expenditures (excluding allowance for equity funds used during construction)	(512,534)	(978,672)
Contributions in aid of construction costs	2,349	42,554
(Advances to) repayments from affiliates, net	(364,000)	63,534
Proceeds from the sale of assets	5,033	16,955
Net cash used in investing activities	(875,514)	(912,415)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,587,943	3,511,930
Principal payments on debt	(1,501,487)	(2,928,044)
Net proceeds from issuance of Limited Partner Units	578,924	34,965
Capital contribution from General Partner	3,354	
Distributions to partners	(465,827)	(447,423)
Debt issuance costs	(7,746)	(20,897)
Net cash provided by financing activities	195,161	150,531
INCREASE IN CASH AND CASH EQUIVALENTS	22,327	2,079
CASH AND CASH EQUIVALENTS, beginning of period	91,902	56,467
CASH AND CASH EQUIVALENTS, end of period	$ 114,229	$ 58,546

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

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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, 2008, 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 (collectively, ETP , we or the Partnership) as of June 30, 2009 and for the three and six months ended June 30, 2009 and 2008, 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 August 10, 2009, 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, 2009, and the Partnership s results of operations and cash flows for the three and six months ended June 30, 2009 and 2008. 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, 2008, as filed with the SEC on March 2, 2009.

Certain prior period amounts have been reclassified to conform to the 2009 presentation. These reclassifications had no impact on net income or total partners capital.

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 subsidiary operating partnerships (collectively the Operating Partnerships) as follows:

La Grange Acquisition, L.P., dba 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, Arizona, 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), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, L.L.C. (ETC MEP), all of which are Delaware limited liability companies 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.

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.

The Partnership, the Operating Partnerships and their subsidiaries are collectively referred to in this report as we , us , ETP , Energy Transfer or the Partnership .

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS:

Use of Estimates

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

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream 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, 2009 and 2008 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.

New Accounting Standards and Changes to Significant Accounting Policies

A retrospective adjustment has been made to prior period income per limited partner unit presented in our consolidated statements of operations to conform to current period presentation related to our adoption of EITF 07-4. EITF 07-4 and other recently adopted accounting standards are discussed below.

Emerging Issues Task Force Issue No. 07-4, *Application of the Two Class Method Under FASB Statement No. 128, to Master Limited Partnerships* (EITF 07-4). The Financial Accounting Standards Board (FASB) ratified the final consensus on EITF 07-4 on March 26, 2008. The key elements of the final consensus relate to: (a) the scope of the issue; (b) when Incentive Distribution Rights (IDRs) are considered participating securities under the two-class method for Earnings Per Share (EPS); (c) the calculation provisions; and (d) the transition and effective date. EITF 07-4 addresses how current period earnings of a master limited partnership (MLP) should be allocated to the general partner, limited partners, and, when applicable, the holder of IDRs when applying the two-class method under Statement 128. EITF 07-4 applies to MLPs that are required to make incentive distributions when certain thresholds have been met regardless of whether the IDR is a separate limited partner interest or embedded in the general partner interest. EITF 07-4 only addresses incentive distributions that are treated as equity distributions and does not address whether the incentive distributions are compensation or equity distributions. Specifically, if IDRs are separate from the general partner interest, then they are considered separate participating securities for purposes of applying the two-class method of determining EPS. Under this situation, the two-class method is used to determine EPS for the general partner interest, limited partner interest and the IDR holders interest. EITF 07-4 provides that when earnings for the period exceed distributions, the excess undistributed earnings are to be allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of income. When distributions for the period exceed earnings, the income is first allocated equally to the actual distributions. The resulting deficit is allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership

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agreement related to the allocation of losses. We recorded and disclosed EPS information following the previous GAAP until January 1, 2009. We adopted EITF 07-4 as required on January 1, 2009 and have applied EITF 07-4 retrospectively; therefore, earnings per unit amounts for prior periods have been restated.

Based on the terms of our partnership agreement, EITF 07-4 requires us to allocate any excess undistributed earnings to the general partner and limited partners based on their respective ownership interests, with none of the excess undistributed earnings allocated to the IDRs. Prior to the adoption of EITF 07-4, we allocated a portion of the excess undistributed earnings to the IDRs. Thus, for periods where earnings exceed distributions, EITF 07-4 will result in a higher income per limited partner unit than our previous approach. For periods where distributions exceed earnings, the calculation of income per limited partner unit under EITF 07-4 is consistent with our previous approach. Thus, the adoption of EITF 07-4 will not have an impact on those periods.

The following financial table sets forth the effect of the retrospective application of EITF 07-4 on income per limited partner unit for the three and six months ended June 30, 2008:

	Three Months Ended June 30, 2008		Six Months Ended June 30, 2008	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted
Basic net income per limited partner unit	$ 0.61	$ 0.61	$ 2.13	$ 2.39
Diluted net income per limited partner unit	$ 0.60	$ 0.60	$ 2.12	$ 2.38

Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations,* (SFAS 141R). On December 4, 2007, the FASB issued SFAS 141R, which significantly changes the accounting for business combinations. Under SFAS 141R, an acquiring entity is required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. Statement 141R changes the accounting treatment for certain specific items, including:

- Acquisition costs are generally expensed as incurred;
- Noncontrolling interests (previously referred to as minority interests) are valued at fair value at the acquisition date;
- In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;
- Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

SFAS 141R also includes a substantial number of new disclosure requirements. SFAS 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Our adoption of SFAS 141R on January 1, 2009 did not have an immediate impact on our financial position or results of operations.

Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133* (SFAS 161). Issued in March 2008, SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 did not impact our financial position or results of operations.

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FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). FSP EITF 03-6-1 was issued by the FASB on June 16, 2008. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. We adopted FSP EITF 03-6-1 effective January 1, 2009. Based on unvested unit awards outstanding at the time of adoption, application of FSP EITF 03-6-1 did not have a material impact on our computation of earnings per unit.

Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations* (EITF 08-6). EITF 08-6 establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment. EITF 08-6 also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. Our adoption of EITF 08-6 on January 1, 2009 did not have a material impact on our financial condition or results of operations.

Statement of Financial Accounting Standards Staff Position (FSP) SFAS 157-2, *Effective Date of FASB Statement No. 157 (FSP 157-2)*. FSP 157-2 deferred the effective date of Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* (SFAS 157) for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), such as impaired nonfinancial assets and certain assets and liabilities acquired in business combinations. Our adoption of FSP 157-2 on January 1, 2009 did not impact our financial condition or results of operations.

Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events* (SFAS 165). In May 2009, the FASB issued SFAS 165 which incorporates requirements for recording and disclosing subsequent events into the accounting standards; those requirements had previously existed only in the auditing standards. The requirements in SFAS 165 are consistent with the practices that had previously been applied, but SFAS 165 also requires disclosure with respect to the date through which subsequent events are evaluated. Under SFAS 165, we are required to evaluate subsequent events through the date that our financial statements are issued. The adoption of SFAS 165 does not change our current practices with respect to evaluating, recording and disclosing subsequent events; therefore, our adoption of this statement during the second quarter had no impact on our financial position or results of operations.

Statement of Financial Accounting Standards No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168). In June 2009, the FASB issued SFAS 168 which establishes the *FASB Accounting Standards Codification* (the Codification). The Codification reorganizes existing accounting pronouncements but does not change GAAP. The new structure is organized into approximately 90 accounting topics and is further organized into subtopics, sections and subsections. Once the Codification becomes effective, all non-grandfathered, non-SEC accounting literature not included in the Codification will become non-authoritative. Although the Codification will not have an impact on our accounting policies or our financial position or results of operations, it will change the way that we reference accounting standards in our financial statements beginning with financial statements we will issue for the quarter ending September 30, 2009.

3. <u>CASH, CASH EQUIVALENTS AND SUPPLEMENTAL CASH FLOW INFORMATION</u>:

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 which 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 (FDIC) insurance limit.

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

	Six Months Ended June 30, 2009	2008
Net income	$ 457,905	$ 494,009
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	148,777	121,249
Amortization of finance costs charged to interest	4,152	2,575
Provision for loss on accounts receivable	2,825	2,802
Non-cash unit-based compensation expense	14,483	11,960
Non-cash executive compensation expense	625	625
Deferred income taxes	9,703	891
Losses on disposal of assets	245	936
Allowance for equity funds used during construction	(18,588)	(25,548)
Distributions on unvested awards	(1,387)	
Distributions in excess of (less than) equity in earnings of affiliates, net	(430)	3,309
Other non-cash	(658)	
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	200,132	(232,767)
Accounts receivable from related companies	(19,240)	108
Inventories	84,695	185,710
Deposits paid to vendors	26,250	(18,110)
Exchanges receivable	17,613	(29,503)
Prepaid expenses and other current assets	20,956	(10,289)
Intangibles and other assets	(2,043)	(1,333)
Accounts payable	(108,183)	309,764
Accounts payable to related companies	(27,323)	(22,453)
Exchanges payable	(31,843)	28,481
Customer advances and deposits	(33,793)	7,253
Accrued and other current liabilities	26,114	(71,709)
Interest payable	44,051	13,726
Income taxes payable	(10,418)	5,154
Other non-current liabilities	(155)	2,277
Price risk management assets and liabilities, net	(101,785)	(15,154)
Net cash provided by operating activities	$ 702,680	$ 763,963

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

	Six Months Ended June 30, 2009	2008
NON-CASH INVESTING ACTIVITIES:		
Investment in Calpine Corporation received in exchange for accounts receivable	$	$ 14,879
Capital expenditures accrued	$ 90,268	$ 173,776
NON-CASH FINANCING ACTIVITIES:		
Capital contribution receivable from general partner	$ 8,932	$ 5,854
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$	$ 3,948

SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$	143,991	$	123,772
Cash paid for income taxes	$	14,073	$	8,707

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4. ACCOUNTS RECEIVABLE:

Accounts receivable consisted of the following:

	June 30, 2009	December 31, 2008
Midstream and intrastate transportation and storage	$ 293,367	$ 415,507
Interstate transportation	30,121	29,309
Propane	73,299	155,191
Less - allowance for doubtful accounts	(8,463)	(8,750)
Total, net	$ 388,324	$ 591,257

The activity in the allowance for doubtful accounts during the six months ended June 30, 2009 consisted of the following:

Balance, December 31, 2008	$ 8,750
Accounts receivable written off, net of recoveries	(3,112)
Provision for loss on accounts receivable	2,825
Balance, June 30, 2009	$ 8,463

5. INVENTORIES:

Inventories consisted of the following:

	June 30, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 124,614	$ 184,727
Propane	39,951	63,967
Appliances, parts and fittings and other	23,089	23,654
Total inventories	$ 187,654	$ 272,348

During the three months ended March 31, 2009, we recorded a lower of cost or market adjustment of $44.6 million for natural gas inventory to reflect market values, which were less than the weighted-average cost. No lower of cost or market adjustments were recorded for the three months ended June 30, 2009 or the six months ended June 30, 2008.

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. During the three months ended June 30, 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, the designated hedged inventory has been recorded at fair value on our condensed consolidated balance sheet, and changes in its fair value have been recorded in cost of products sold in our condensed consolidated statement of operations. At June 30, 2009, $123.5 million of our natural gas inventory was recorded at fair value.

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6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

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

	June 30, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Non-compete agreements (3 to 15 years)	$ 40,305	$ (26,698)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,268	(46,651)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(4,691)	23,015	(3,744)
Other (10 years)	477	(373)	2,677	(2,244)
Total amortizable intangible assets	217,065	(78,413)	210,330	(70,092)
Non-amortizable intangible assets - Trademarks	75,503		75,667	
Total intangible assets	292,568	(78,413)	285,997	(70,092)
Other long-term assets:				
Financing costs (3 to 30 years)	66,855	(20,511)	59,108	(16,586)
Regulatory assets	105,789	(7,720)	98,560	(5,941)
Other	44,224		43,153	
Total intangibles and other assets	$ 509,436	$ (106,644)	$ 486,818	$ (92,619)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Reported in depreciation and amortization	$ 4,983	$ 4,321	$ 9,692	$ 8,620
Reported in interest expense	$ 2,048	$ 1,570	$ 3,926	$ 2,852

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

Years Ending December 31:	
2010	$ 26,695
2011	25,030
2012	21,445
2013	16,014
2014	15,000

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review goodwill and non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate segment and as of August 31 for all others. No impairment of intangible assets was required for the three and six months ended June 30, 2009 or 2008. In December 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No goodwill impairment losses were recorded during the three and six months ended June 30, 2009 or 2008.

A decrease in goodwill of $8.7 million was recorded during the three months ended March 31, 2009 in connection with purchase price allocation adjustments related to prior acquisitions of propane businesses.

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7. ACCRUED AND OTHER CURRENT LIABILITIES:

Accrued and other liabilities consisted of the following:

	June 30, 2009	December 31, 2008
Accrued wages and benefits	$ 65,689	$ 64,692
Accrued capital expenditures	90,268	153,230
Taxes other than income taxes	52,898	20,772
Other	64,198	73,294
Total accrued and other current liabilities	$ 273,053	$ 311,988

8. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

We are party to an agreement with Kinder Morgan Energy Partners, L.P. (KMP) for a 50/50 joint development of Midcontinent Express pipeline (MEP). Construction of the approximately 500-mile pipeline was completed and natural gas transportation service commenced August 1, 2009 on the pipeline from Delhi, Louisiana, to an interconnect with the Transco interstate natural gas pipeline in Butler, Alabama. Interim service began on the pipeline from Bennington, Oklahoma, to Delhi in April 2009. In July 2008, MEP completed an open season with respect to a capacity expansion of MEP from the original planned capacity of 1.5 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to an interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional 300 MMcf/d of capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is pending approval from the Federal Energy Regulatory Commission (the FERC).

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

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 187-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 Quitman County, Mississippi. FEP, the entity formed to construct, own and operate this pipeline, filed with the FERC on June 15, 2009 to request a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act and related authorizations. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. Pending necessary regulatory approvals, the pipeline project is expected to be in service by early 2011. FEP has secured binding 10-year commitments 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. Pursuant to our agreement with KMP related to this project, we and KMP are each obligated to fund 50% of the equity necessary to construct the project.

Capital Contributions to Affiliates

During the six months ended June 30, 2009, we contributed $333.0 million to MEP and $31.0 million to FEP. With respect to MEP, capital expenditures were previously funded under a $1.4 billion credit facility (reduced to $1.3 billion due to the bankruptcy of Lehman Brothers). As this facility became substantially drawn during the first quarter of 2009, we and KMP have made and will continue to make capital contributions to MEP to fund capital expenditures until the project is completed. We expect that our capital contributions to MEP during the last six months of 2009 will be between $320.0 million and $340.0 million, which includes amounts to fund remaining expenditures for the project and an additional capital contribution to reduce the indebtedness of MEP to a level expected to be needed to obtain long-term financing for MEP, on a stand-alone basis without guarantees

from ETP or KMP, on acceptable terms. With respect to FEP, we expect that our capital contributions will be between $160.0 million and $180.0 million during the last six months of 2009 to fund expenditures for the project. FEP intends to pursue financing (expected to be severally guaranteed by ETP and KMP), which, if arranged during the last six months of 2009, would reduce the level of expected capital contributions this year as capital expenditures for the project would be funded at the project level; however, the availability of such financing at agreeable terms remains uncertain.

9. FAIR VALUE MEASUREMENTS:

The carrying amounts of 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, 2009 was $5.99 billion and $5.74 billion, respectively. At December 31, 2008, the aggregate fair value and carrying amount of long-term debt was $5.10 billion and $5.66 billion, respectively.

The following table summarizes the fair value of our financial assets and liabilities as of June 30, 2009 and December 31, 2008, based on inputs used to derive their fair values in accordance with SFAS 157:

		Fair Value Measurements at June 30, 2009 Using			Fair Value Measurements at December 31, 2008 Using	
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets:						
Marketable securities	$ 9,630	$ 9,630	$	$ 5,915	$ 5,915	$
Inventories	123,460	123,460				
Commodity derivatives	9,492	7,038	2,454	111,513	106,090	5,423
Interest rate swap derivatives	1,818		1,818			
Liabilities:						
Commodity derivatives	(196)		(196)	(43,336)		(43,336)
Interest rate swap derivatives	(1,532)		(1,532)	(51,642)		(51,642)
	$ 142,672	$ 140,128	$ 2,544	$ 22,450	$ 112,005	$ (89,555)

During the three months ended June 30, 2009, we began designating certain commodity derivatives that are utilized to manage price volatility associated with our natural gas inventory as fair value hedges. Prior to April 2009, our natural gas inventory was recorded at weighted-average cost and therefore was not included in the table above. We consider the fair value of our hedged natural gas inventory to be a Level 1 valuation because it is stored at delivery points with active markets for which published prices are available.

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10. 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, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Current expense (benefit):				
Federal	$ (771)	$ 5,369	$ (5,107)	$ 4,846
State	3,377	5,350	6,895	8,622
Total	2,606	10,719	1,788	13,468
Deferred expense (benefit):				
Federal	2,041	(223)	9,142	2,611
State	(88)	(454)	561	(175)
Total	1,953	(677)	9,703	2,436
Total income tax expense	$ 4,559	$ 10,042	$ 11,491	$ 15,904
Effective tax rate	2.9%	5.7%	2.4%	3.1%

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.

11. INCOME PER LIMITED PARTNER UNIT:

Our net income is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. The adoption of EITF 07-4 on January 1, 2009, as discussed in Note 2, required us to change our calculation of earnings per unit during periods where earnings exceeded distributions. Under EITF 07-4, earnings in excess of distributions are now allocated to the General Partner and Limited Partners based on their respective ownership interests. Previously, a portion of earnings in excess of distributions had been allocated to the General Partner with respect to the IDRs. We have applied EITF 07-4 retrospectively; therefore, earnings per unit amounts for prior periods have been restated.

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, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net income	$ 150,738	$ 165,674	$ 457,905	$ 494,009
General Partner s interest in net income	87,179	78,983	177,469	153,347
Limited Partners interest in net income	63,559	86,691	280,436	340,662
Distributions on employee unit awards, net of allocation to General Partner	(651)		(1,349)	
Net income available to Limited Partners	$ 62,908	$ 86,691	$ 279,087	$ 340,662
Weighted average Limited Partner units basic	166,596,074	142,827,051	161,829,139	142,794,658

Basic net income per Limited Partner unit	$ 0.38	$ 0.61	$ 1.72	$ 2.39
Weighted average Limited Partner units	166,596,074	142,827,051	161,829,139	142,794,658
Dilutive effect of Unit Grants	601,047	526,253	555,692	529,120
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	167,197,121	143,353,304	162,384,831	143,323,778
Diluted net income per Limited Partner unit	$ 0.38	$ 0.60	$ 1.72	$ 2.38

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12. DEBT OBLIGATIONS:

ETP Senior Notes

2009 ETP Notes

In April 2009, we completed a public offering of $350.0 million aggregate principal amount of 8.50% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.00% Senior Notes due 2019 (collectively the 2009 ETP Notes). The offering of the 2009 ETP Notes closed on April 7, 2009 and we used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

The 2009 ETP Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the 2009 ETP Notes is not guaranteed by any of the Partnership s subsidiaries. As a result, the 2009 ETP Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the 2009 ETP Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

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). 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 indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of June 30, 2009, there was no balance outstanding on the ETP Credit Facility and taking into account letters of credit of approximately $59.8 million, $1.94 billion was available for future borrowings.

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, 2009, there was no outstanding balance in revolving credit loans and $1.0 million in outstanding letters of credit. The amount available as of June 30, 2009 was $74.0 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, 2009.

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13. PARTNERS CAPITAL:

Common Units Issued

The change in Common Units during the six months ended June 30, 2009 is as follows:

	Number of Units
Balance, December 31, 2008	152,102,471
Common Units issued in connection with public offerings	16,675,000
Issuance of Common Units under equity incentive plans	8,988
Balance, June 30, 2009	168,786,459

In January 2009, we closed a public offering of 6,900,000 Common Units at $34.05 per Common Unit. Net proceeds of approximately $225.9 million from the offering were used to repay outstanding borrowings under the ETP Credit Facility.

In April 2009, we closed a public offering of 9,775,000 Common Units at $37.55 per Common Unit. The proceeds of approximately $352.4 million, net of underwriting discounts and commissions, were used to fund capital expenditures and capital contributions to joint venture entities related to pipeline construction projects as well as for general partnership purposes. The units were registered under the Securities Act pursuant to a Registration Statement on Form S-3ASR.

Quarterly Distributions of Available Cash

On February 13, 2009, we paid a per unit cash distribution related to the three months ended December 31, 2008 of $0.89375 per Common Unit ($3.575 per Limited Partner Unit annualized) to Unitholders of record at the close of business on February 6, 2009. We paid distributions of $83.9 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its IDRs for the three months ended December 31, 2008.

On May 15, 2009, we paid a per unit cash distribution related to the three months ended March 31, 2009 of $0.89375 per Common Unit ($3.575 per Limited Partner Unit annualized) to Unitholders of record at the close of business on May 8, 2009. We paid distributions of $89.0 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its IDRs for the three months ended March 31, 2009.

On July 28, 2009, we declared a cash distribution for the three months ended June 30, 2009 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 14, 2009 to Unitholders of record at the close of business on August 7, 2009.

Total distributions declared (all from Available Cash from Operating Surplus) related to the six months ended June 30, 2009 were as follows:

Limited Partners -	
Common Units	$ 301,738
Class E Units	6,242
General Partners -	
2% Ownership	9,721
Incentive Distribution Rights	168,310
	$ 486,011

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Accumulated Other Comprehensive Income

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

	June 30, 2009	December 31, 2008
Net gains (losses) on commodity related derivatives	$ (863)	$ 8,735
Net gains on interest rate derivatives	16	161
Unrealized losses on available-for-sale securities	(2,275)	(5,983)
Total AOCI, net of tax	$ (3,122)	$ 2,913

14. <u>UNIT-BASED COMPENSATION PLANS</u>:

Employee Grants

The following table shows the activity of the awards during the six months ended June 30, 2009:

	Three-Year Performance Vesting (1)		Five-Year Service Vesting (2)		Other (3)		Total	
	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2008	150,852	$ 43.96	1,205,430	$ 35.87	8,976	$ 43.48	1,365,258	$ 36.81
Awards granted			35,850	34.60			35,850	34.60
Awards vested	(2,036)	43.96	(50,670)	38.27			(52,706)	38.49
Awards forfeited	(3,336)	43.96	(23,531)	36.51			(26,867)	37.44
Unvested awards as of June 30, 2009	145,480	$ 43.96	1,167,079	$ 35.71	8,976	$ 43.48	1,321,535	$ 36.67

(1) Includes awards subject to performance objectives and continued employment.

(2) Includes awards for which vesting is subject to continued employment.

(3) Includes special grants and awards issued with other vesting conditions.

As of June 30, 2009, a total of 4,785,940 ETP Common Units remain available to be awarded under our equity incentive plans.

We recognized non-cash compensation expense related to employee grants under our unit-based compensation plans of $5.8 million and $5.5 million for the three months ended June 30, 2009 and 2008, respectively. We recognized non-cash compensation expense related to employee grants under our unit-based compensation plans of $10.8 million and $11.4 million for the six months ended June 30, 2009 and 2008, respectively. The total expected non-cash compensation expense to be recognized related to the unvested employee awards as of June 30, 2009 is:

Years Ending December 31:	
2009 (remainder)	$ 9,009
2010	10,038
2011	5,896
2012	3,089
2013	1,010

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Director Grants

There were no new director grants or awards vested during the six months ended June 30, 2009.

We recognized non-cash compensation expense related to director grants under our unit-based compensation plans of $0.04 million and $0.03 million for the three months ended June 30, 2009 and 2008, respectively. We recognized non-cash compensation expense related to director grants under our unit-based compensation plans of $0.08 million and $0.07 million for the six months ended June 30, 2009 and 2008, respectively.

Related Party Awards

During 2007 and 2008, a partnership (McReynolds Energy Partners, L.P.), the general partner of which is owned and controlled by the President of our General Partner, awarded to certain officers of ETP certain rights related to units of Energy Transfer Equity, L.P. (ETE) previously issued by ETE to such officer. As of June 30, 2009, rights related to 695,000 unvested ETE units remained outstanding. In June 2008, 240,000 unit awards were forfeited due to the resignation of an officer of ETP. For the three months ended June 30, 2009, we recognized non-cash compensation expense of $1.8 million. For the three months ended June 30, 2008, we recognized non-cash compensation expense of $1.0 million related to these awards and reversed $2.7 million of previously recognized compensation cost related to the forfeiture of these awards, for a net benefit of $1.7 million. For the six months ended June 30, 2009 and 2008, we recognized non-cash compensation expense of $3.7 million and $0.5 million, respectively, related to these awards.

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

Regulatory Matters

Approval from the FERC is pending on our current pipeline construction projects, including MEP and FEP, as discussed in Note 8, and the Tiger Pipeline. We initiated public review of the Tiger pipeline pursuant to the FERC s National Environmental Policy Act (NEPA) pre-filing review process in March 2009.

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.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (Order). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service effective March 2009.

Guarantees

We have guaranteed 50% of the obligations of MEP under its $1.4 billion senior revolving credit facility (the MEP Facility), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage of MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. The MEP Facility is syndicated among multiple financial institutions. As a result of the Lehman Brothers bankruptcy in 2008, the MEP Facility has effectively been reduced by the Lehman Brothers affiliate s commitment of approximately $100.0 million. However, the MEP Facility is not in default, and the commitments of the other lending banks remain unchanged.

As of June 30, 2009, MEP had $1.19 billion of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $595.4 million and $16.6 million, respectively, as of June 30, 2009.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and 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 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 that require fixed monthly rental payments and expire at various dates through 2020. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.5 million and $7.2 million for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, rental expense totaled approximately $11.5 million and $15.4 million, respectively, for operating leases.

As discussed in Note 8, we also have commitments to make capital contributions to our joint ventures.

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/CFTC 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 alleges 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. 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. The FERC specified that it was also seeking to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based prices would be limited to sales to retail customers (such as utilities and other end-users) and sales from our own production, and any other sales of natural gas by us would be required to be made at contract prices that would be subject to individual FERC approval.

Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to the FERC-approved rates, terms and conditions of service. The Order and Notice alleged that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of

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similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC specified that it was seeking approximately $15.5 million in civil penalties and disgorgement of overcharges related to these claims against Oasis. On May 15, 2008, the FERC ordered a hearing to be conducted by a FERC administrative law judge with respect to the Oasis claims. The hearing related to the Oasis claims was scheduled to commence in December 2008 with the administrative law judge s initial decisions due by May 11, 2009; however, on November 18, 2008, the administrative law judge presiding over the Oasis claims granted our motion for summary disposition of the claim that Oasis unduly discriminated in favor of affiliates regarding the provision of Section 311(a)(2) interstate transportation service. We subsequently entered into an agreement with the Enforcement Staff to settle all of the claims related to Oasis. Pursuant to this agreement, Oasis will not pay any civil penalties to the FERC or make any other payments. On January 5, 2009, this agreement was submitted under seal to FERC by the presiding administrative law judge, for FERC s approval as an uncontested settlement of all Oasis claims. On February 27, 2009, the settlement agreement was approved by the FERC in its entirety and without modification, and the terms of the settlement were made public. The FERC s order is now final and non-appealable. We believe the Oasis settlement, as approved by the FERC, will not have a material adverse effect on our business, financial condition or results of operations.

On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed the FERC Enforcement Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The 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 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 March 31, 2008, we responded to the Enforcement Staff s brief.

On May 15, 2008, the FERC ordered a hearing to be conducted by a FERC administrative law judge with respect to the FERC s market manipulation claims. In this order, the FERC set for hearing the Enforcement Staff s claims for the additional month in 2005, bringing the total amount of civil penalties and disgorgement of profits sought by the FERC relating to its market manipulation claims to approximately $181.9 million, excluding interest. The hearing related to the market manipulation claims was scheduled to commence in July 2009 with the administrative law judge s initial decision due by January 7, 2010; however, as discussed below, the procedural schedule (including the commencement of the hearing) has been postponed to August 12, 2009. The FERC also ordered that, following the completion of the hearings, the administrative law judges make initial findings with respect to whether we engaged in market manipulation in violation of the NGA and FERC regulations. The FERC reserved for itself the issues of possible civil penalties, revocation of our blanket market certificate and whether we would disgorge any unjust profits. Following the issuance of the administrative law judge s initial decision related to the market manipulation claims, the FERC would then issue an order with respect to each of these matters. On May 23, 2008, we requested rehearing and stay of the FERC s May 15, 2008 order establishing hearing, and we renewed those requests on June 26, 2008. On August 7, 2008, the FERC denied rehearing of its May 15, 2008 order. On August 8, 2008, we filed a petition with the U.S. Court of Appeals for the Fifth Circuit to review and set aside the FERC s May 15 and August 7, 2008 orders on the grounds that we are entitled to adjudicate the FERC s claims in federal district court pursuant to the NGA and the NGPA. On August 28, 2008, we filed an amended petition seeking review of the Order and Notice and the December 20, 2007 order denying rehearing. The Fifth Circuit dismissed our petition without reaching the merits on April 28, 2009. On June 12, 2009, we sought rehearing and rehearing en banc of the Court s April 28, 2009 order. On July 1, 2009, the Fifth Circuit denied our requests for rehearing.

On July 10, 2009, the chief administrative law judge issued an order suspending the procedural schedule and all hearing-related matters with respect to the FERC s market manipulation claims until August 12, 2009 in light of settlement discussions occurring between us and Enforcement Staff.

It is our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC holds substantial enforcement authority.

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In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE alleging damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain 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 the suits against us and ETE contains an additional allegation that we and ETE transported gas in a manner that favored our affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have moved to compel arbitration and/or contested subject-matter jurisdiction in some of these cases. In one of these cases, the Texas Supreme Court ruled on July 3, 2009 that the state district court erred in ruling that a plaintiff was entitled to pre-arbitration discovery and therefore remanded to the state district court with a direction to rule on our original motion to compel arbitration pursuant to the terms of the arbitration clause in a natural gas contract between us and the plaintiff. This plaintiff has filed a motion with the Texas Supreme Court requesting a rehearing of the ruling.

We have also been served with a complaint from 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. This action is currently on appeal before the First Court of Appeals, Houston.

A consolidated class action complaint has been 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. The plaintiffs have since moved for reconsideration, and briefing on that motion is now complete.

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 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.

We are expensing the legal fees, consultants fees and other expenses relating to these matters in the periods in which such expenses are incurred. In addition, our existing accruals for litigation and contingencies include an accrual related to these matters. However, it is possible that the amount we become obliged to pay as a result of the final resolution of these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of our existing accrual 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 existing 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.

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariff, which were filed with and approved by the FERC. As a result, Transwestern believes that is has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. A hearing was held on April 24, 2007 regarding Transwestern s Supplemental Brief for Attorneys fees which was filed on January 8, 2007 and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg s opening brief was filed on or about July 31, 2007. Appellee s opposition brief was filed on or about November 21, 2007. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg s reply brief was filed in June 2008 and the hearing on all briefs was held in September 2008. On March 17, 2009, the Tenth Circuit affirmed the District Court s dismissal. We do not believe the outcome of this case will have a material adverse effect on our financial position, results of operations or cash flows.

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 engaged in ongoing 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 . Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have 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. AEP is appealing the court decision. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

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 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.

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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.

As of June 30, 2009 and December 31, 2008, accruals of approximately $21.0 million were recorded as accrued and other current liabilities and other non-current liabilities on our condensed consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters and matters covered by insurance.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and 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 and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. 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 health, and the handling, storage, use and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

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 by 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 $8.9 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern continues to incur certain costs related to PCBs that might have migrated through its pipelines into customers facilities in the past. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing the PCBs. Costs of these remediation activities were minimal for both the three and six months ended June 30, 2009. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at June 30, 2009. 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.

In July 2001, HOLP acquired a company that had previously received a request for information from the EPA regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). We have not received

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any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to HOLP, it is believed that HOLP s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

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 condensed 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.

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

As of June 30, 2009 and December 31, 2008, an accrual on an undiscounted basis of $12.9 million and $13.3 million, respectively, was recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover environmental liabilities related to certain matters assumed in connection with the HPL System acquisition, the Transwestern acquisition and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

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

Our pipeline operations are subject to regulation by the U.S. Department of Transportation 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 (the IMP 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, 2009 and 2008, $11.6 million and $4.0 million, respectively, of capital costs and $5.6 million and $7.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the six months ended June 30, 2009 and 2008, $15.3 million and $5.5 million, respectively, of capital costs and $9.0 million and $10.7 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.

16. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

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 over-the-counter (OTC) commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the condensed 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.

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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 segment to hedge the sales price of retention gas 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 have a risk management policy that specifies the manner in which derivative financial instruments are employed and monitored in connection with underlying asset, liability and/or anticipated transactions. Furthermore, on a bi-weekly basis, management reviews the creditworthiness of the derivative counterparties to manage against the risk of default.

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

Non-trading Activities

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

We expect losses of $2.3 million related to commodity derivatives to be reclassified into earnings over the next twelve months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

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

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. Changes in the spreads between the forward natural gas prices designated as fair value hedges and the physical Bammel inventory spot price result in unrealized margins 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/losses associated with these positions are realized.

We attempt to maintain balanced positions in our non-trading 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.

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Trading Activities

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the condensed consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the condensed consolidated statements of operations on a net basis. There were no gains or losses associated with trading activities during the three and six months ended June 30, 2009. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.1 million for the year-to-date period ended July 31, 2008.

The following table details the outstanding commodity-related derivatives:

June 30, 2009

	Commodity	Notional Volume	Maturity
Mark to Market Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	50,700,000	2009-2011
Swing Swaps IFERC (MMBtu)	Gas	(44,095,000)	2009-2010
Fixed Swaps/Futures (MMBtu)	Gas	4,567,500	2009-2011
Forwards/Swaps (Gallons)	Propane/Ethane	15,078,000	2009-2010
Fair Value Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	(31,117,500)	2009-2010
Fixed Swaps/Futures (MMBtu)	Gas	(31,990,000)	2009-2010
Hedged Item - Inventory	Gas	31,990,000	2009-2010
Cash Flow Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	460,000	2009
Fixed Swaps/Futures (MMBtu)	Gas	460,000	2009
Forward/Swaps (Gallons)	Propane/Ethane	18,858,000	2009-2010

December 31, 2008

	Commodity	Notional Volume	Maturity
Mark to Market Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	15,720,000	2009-2011
Swing Swaps IFERC (MMBtu)	Gas	(58,045,000)	2009
Fixed Swaps/Futures (MMBtu)	Gas	(20,880,000)	2009-2010
Forwards/Swaps (Gallons)	Propane	47,313,002	2009
Cash Flow Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	(9,085,000)	2009
Fixed Swaps/Futures (MMBtu)	Gas	(9,085,000)	2009

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps, certain of which are accounted for as cash flow hedges. As of June 30, 2009, we have forward starting swaps with a notional amount of $500.0 million to pay an average fixed rate of 3.99% and receive a floating rate based on LIBOR. These swaps settle in December 2009.

In April 2009, the Partnership terminated forward starting swaps with notional amounts of $100.0 million and $150.0 million for an insignificant amount.

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Derivative Summary

The following table provides a balance sheet overview of the Partnership s derivative assets and liabilities as of June 30, 2009 and December 31, 2008:

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	June 30, 2009	December 31, 2008	June 30, 2009	December 31, 2008
Derivatives designated as hedging instruments under SFAS 133:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 17,424	$ 10,665	$ (5,547)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	1,457	918	(93)	(119)
Total derivatives designated as hedging instruments		$ 18,881	$ 11,583	$ (5,640)	$ (1,623)
Derivatives not designated as hedging instruments under SFAS 133:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	20,809	432,614	(25,648)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	1,172	17,244	(278)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	1,818		(1,532)	(51,643)
Total derivatives not designated as hedging instruments		$ 23,799	$ 449,858	$ (27,458)	$ (443,282)
Total derivatives		$ 42,680	$ 461,441	$ (33,098)	$ (444,905)

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

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. 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 in the condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $52.0 million and $78.2 million as of June 30, 2009 and December 31, 2008, respectively, reflected as deposits paid to vendors in our condensed consolidated balance sheets.

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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:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Change in Value Recognized in OCI on Derivatives (Effective Portion) Three Months Ended June 30, 2009	2008	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30, 2009	2008	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives Three Months Ended June 30, 2009	2008
Derivatives in SFAS 133 cash flow hedging relationships:							
Commodity Derivatives	Cost of Products Sold	$ 1,336	$ (1,312)	$ (928)	$ (9,689)	$	$ (16)
Interest Rate Swap Derivatives	Interest Expense			72	216		
Total		$ 1,336	$ (1,312)	$ (856)	$ (9,473)	$	$ (16)

		Six Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Derivatives in SFAS 133 cash flow hedging relationships:							
Commodity Derivatives	Cost of Products Sold	$ (50)	$ (7,573)	$ 9,549	$ 21,183	$	$ (8,336)
Interest Rate Swap Derivatives	Interest Expense			144	501		
Total		$ (50)	$ (7,573)	$ 9,693	$ 21,684	$	$ (8,336)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives representing hedge ineffectiveness and amount excluded from the assessment of effectiveness Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Derivatives in SFAS 133 fair value hedging relationships:					
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ 12,498	$	$ 12,498	$
Total		$ 12,498	$	$ 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, 2009	2008	Six Months Ended June 30, 2009	2008
Derivatives not designated as hedging instruments under SFAS 133:					
Commodity Derivatives	Cost of Products Sold	$ 5,138	$ (38,732)	$ 56,576	$ (83,578)
Trading Commodity Derivatives	Revenue		9,139		8,446
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate	36,842	355	50,568	(245)

Derivatives

Total	$	41,980	$	(29,238)	$	107,144	$	(75,377)

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 that allow for netting of positive and negative exposure associated with a single counterparty.

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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 sheets and recognized in net income or other comprehensive income.

17. RELATED PARTY TRANSACTIONS:

We made the following sales to and purchases from affiliates of Enterprise GP Holdings L.P. (Enterprise):

		Three Months Ended June 30,				Six Months Ended June 30,			
		2009		2008		2009		2008	
Enterprise Transactions	Product	Volumes (in thousands)	Dollars	Volumes (in thousands)	Dollars	Volumes (in thousands)	Dollars	Volumes (in thousands)	Dollars
Propane Operations:									
Sales	Propane (Gallons)	7,770	$ 5,226	3,150	$ 5,050	16,800	$ 11,508	12,180	$ 18,240
	Derivative Activity				453				2,376
Purchases	Propane (Gallons)	44,623	$ 36,348	27,473	$ 78,857	159,220	$ 138,274	168,595	$ 278,383
	Derivative Activity		4,657				37,949		
Natural Gas Operations:									
Sales	NGLs (Gallons)	124,983	$ 85,014	8,591	$ 14,754	240,838	$ 151,199	15,977	$ 24,913
	Natural Gas (MMBtu)	2,843	6,360	1,430	13,817	4,098	16,049	3,032	26,678
	Fees		(783)		1,486		(2,174)		3,158
Purchases	Natural Gas Imbalances	(1,270)	$ (559)	2,775	$ 7,608	251	$ 499	1,981	$ 2,920
	Natural Gas (MMBtu)	894	3,066	7,738	32,201	3,596	15,614	5,329	51,973
	Fees		181		257		233		512

Accounts receivable from and accounts payable to related companies as of June 30, 2009 and December 31, 2008 relate primarily to activities in the normal course of business.

Titan purchases substantially all of its propane requirements from Enterprise pursuant to an agreement that expires in 2010. As of June 30, 2009 and December 31, 2008, Titan had forward mark-to-market derivatives for approximately 15.1 million and 45.2 million gallons of propane at a fair value asset of $0.9 million and a fair value liability of $40.1 million, respectively, with Enterprise. In addition, as of June 30, 2009, Titan had forward derivatives accounted for as cash flow hedges of 18.8 million gallons of propane at a fair value asset of $1.3 million with Enterprise.

ETC OLP and 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 summarizes the related party balances with Enterprise on our condensed consolidated balance sheets:

	June 30, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 30,551	$ 11,558
Accounts payable	866	567
Imbalance payable	(1,194)	(547)
Propane Operations:		
Accounts receivable	$ 742	$ 111

Accounts payable	5,166	33,308

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Accounts receivable from related companies excluding Enterprise consist of the following:

	June 30, 2009	December 31, 2008
ETP GP	$ 207	$ 122
ETE	4,888	2,632
MEP	137	2,805
McReynolds Energy		202
Energy Transfer Technologies, Ltd.	11	16
Others	794	449
Total accounts receivable from related companies excluding Enterprise	$ 6,037	$ 6,226

The Chief Executive Officer (CEO) of our General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards. We recorded non-cash compensation expense and an offsetting capital contribution of $0.6 million ($0.2 million in salary and $0.4 million in accrued bonuses) for the six months ended June 30, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

18. 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:
  - intrastate transportation and storage
  - interstate transportation
  - midstream
- retail propane and other retail propane related operations

Segments below the quantitative thresholds are classified as other . The components of the other classification have not met any of the quantitative thresholds for determining reportable segments. Management has included the wholesale propane operations in other for all periods presented in this report because such operations are not material.

Midstream and intrastate transportation and storage segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general and administrative expenses, gains (losses) on disposal of assets, interest expense, equity in earnings (losses) of affiliates and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. We allocate administration expenses from the Partnership to our Operating Partnerships using the Modified Massachusetts Formula Calculation, which is based on factors such as respective segments gross margins, employee costs and property and equipment.

The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month.

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The amounts allocated for the periods presented are as follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Costs allocated from ETP to Operating Partnerships:				
Midstream and intrastate transportation and storage operations	$ 4,478	$ 4,688	$ 10,578	$ 8,585
Interstate operations	1,400	1,353	3,298	2,506
Retail propane and other retail propane related operations	3,452	2,975	8,106	5,525
Total	$ 9,330	$ 9,016	$ 21,982	$ 16,616
Costs allocated from Operating Partnerships to ETP:				
Midstream and intrastate transportation and storage operations	$ 4,291	$ 2,560	$ 8,176	$ 3,933
Retail propane and other retail propane related operations	(33)	752	412	1,353
Total	$ 4,258	$ 3,312	$ 8,588	$ 5,286

The following table presents the financial information by segment for the following periods:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 372,674	$ 1,013,862	$ 828,477	$ 1,979,522
Intersegment revenues	121,260	858,383	294,108	1,373,564
	493,934	1,872,245	1,122,585	3,353,086
Interstate transportation - revenues from external customers	70,585	59,224	131,934	114,640
Midstream:				
Revenues from external customers	504,973	1,302,551	1,099,776	2,289,322
Intersegment revenues	40,795	571,869	77,624	830,862
	545,768	1,874,420	1,177,400	3,120,184
Retail propane and other retail propane related - revenues from external customers	202,272	273,660	718,184	899,375
All other - revenues from external customers	1,313	4,179	3,546	9,988
Eliminations	(162,055)	(1,430,252)	(371,732)	(2,204,426)
Total revenues	$ 1,151,817	$ 2,653,476	$ 2,781,917	$ 5,292,847
Cost of products sold:				
Intrastate transportation and storage	$ 233,951	$ 1,614,660	$ 616,565	$ 2,815,132
Midstream	470,108	1,768,161	1,029,284	2,919,131
Retail propane and other retail propane related	82,886	168,282	307,991	566,013
All other	1,103	3,221	3,024	7,940
Eliminations	(162,055)	(1,430,252)	(371,732)	(2,204,426)
Total cost of products sold	$ 625,993	$ 2,124,072	$ 1,585,132	$ 4,103,790

Depreciation and amortization:				
Intrastate transportation and storage	$ 25,859	$ 20,022	$ 50,892	$ 36,473
Interstate transportation	12,837	9,266	23,496	18,566
Midstream	17,191	13,489	33,701	27,335
Retail propane and other retail propane related	20,174	19,487	40,446	38,573
All other	113	157	242	302
Total depreciation and amortization	$ 76,174	$ 62,421	$ 148,777	$ 121,249

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	Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Operating income (loss):				
Intrastate transportation and storage	$ 156,929	$ 136,370	$ 300,644	$ 324,218
Interstate transportation	31,950	28,491	60,145	57,717
Midstream	28,050	65,269	53,189	117,655
Retail propane and other retail propane related	4,560	(5,523)	168,629	101,432
All other	(1,016)	(336)	(1,782)	(341)
Selling, general and administrative expenses not allocated to segments	(1,253)	1,558	(752)	(1,366)
Total operating income	$ 219,220	$ 225,829	$ 580,073	$ 599,315
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (100,680)	$ (68,416)	$ (182,725)	$ (123,965)
Equity in earnings (losses) of affiliates	1,673	(169)	2,170	(95)
Gains (losses) on disposal of assets	181	515	(245)	(936)
Gains (losses) on non-hedged interest rate derivatives	36,842	355	50,568	(245)
Allowance for equity funds used during construction	(1,839)	15,660	18,588	25,548
Other, net	(100)	1,942	967	10,291
Income tax expense	(4,559)	(10,042)	(11,491)	(15,904)
	(68,482)	(60,155)	(122,168)	(105,306)
Net income	$ 150,738	$ 165,674	$ 457,905	$ 494,009

	As of June 30, 2009	As of December 31, 2008
Total assets:		
Intrastate transportation and storage	$ 4,665,890	$ 4,642,430
Interstate transportation	2,896,988	2,487,078
Midstream	1,573,130	1,537,972
Retail propane and other retail propane related	1,688,568	1,810,953
All other	176,826	149,056
Total	$ 11,001,402	$ 10,627,489

	Six Months Ended June 30, 2009	2008
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 306,096	$ 482,667
Interstate transportation	63,955	444,858
Midstream	54,610	136,738
Retail propane and other retail propane related	33,228	77,147
All other	3,003	205
Total	$ 460,892	$ 1,141,615

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

(Tabular dollar amounts, except per unit data, 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 our previous year ended December 31, 2008 filed with the Securities and Exchange Commission (SEC) on March 2, 2009. 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 for the year ended December 31, 2008.

Overview

Our business activities are primarily conducted through our Operating Partnerships. The Partnership and the Operating Partnerships are sometimes referred to collectively in this report as we , us , Energy Transfer or ETP .

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 amount of cash we will have available for distribution primarily depends on the amount of cash we generate from operations.

During the past several years, we have been successful in completing several acquisitions and business combinations, including the combination of the retail propane operations of Heritage Propane Partners, L.P. and the midstream and intrastate transportation and storage operations of ETC OLP in January 2004. Subsequent to this combination, we have made numerous significant acquisitions, with assets totaling $3.87 billion in our natural gas operations and $849.1 million in our propane operations.

In addition to our acquisitions, we have grown through internal growth projects, consisting primarily of the construction of natural gas transmission pipelines, both intrastate and interstate. From September 1, 2003 through June 30, 2009, we made growth capital expenditures, excluding capital contributions made in connection with the Midcontinent Express pipeline (MEP) and Fayetteville Express pipeline (FEP) joint ventures, of approximately $4.9 billion, of which more than $4.1 billion was related to natural gas transmission pipelines. We expect our fee-based revenue to increase as a result of the completion of recent pipeline expansions to our existing natural gas system in addition to projects expected to be completed in the next twelve to eighteen months. These projects include MEP, the Texas Independence pipeline, FEP and the Tiger pipeline.

Operations

Our principal operations are conducted in the following reportable segments (see Note 18 to our unaudited condensed consolidated financial statements):

Intrastate transportation and storage - Revenue is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline on an interruptible basis. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued based on the published market prices as of the first of the month and sold at market prices. The HPL System also generates revenue from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The use of the Bammel storage reservoir allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin, in addition to generating revenue from fee-based contracts to reserve firm storage capacity.

Interstate transportation - The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

Midstream - Revenue is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, transported, purchased and sold through our pipelines (excluding the transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

Retail propane - Revenue is generated from the sale of propane and propane-related products and services.

Trends and Outlook

In light of the current conditions in the capital markets, and based on our projected growth capital expenditures and capital contributions to joint venture entities, we have taken significant steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate at $3.575 per Common Unit on an annualized basis since the second quarter of 2008, and continuing to appropriately manage operating and administrative costs. During the six months ended June 30, 2009, we received approximately $578.3 million in net proceeds from our January 2009 and April 2009 Common Units offerings and $993.6 million in net proceeds from an offering of $1.0 billion of aggregate principal amount of senior notes in April 2009. As of June 30, 2009, in addition to approximately $114.2 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.94 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 without the need to access the capital markets until the latter half 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 or other partnership purposes.

As noted above and despite the economic challenges and volatile capital markets, we have successfully raised approximately $2.2 billion in proceeds from the recent debt and equity offerings since December 1, 2008, which includes approximately $595.7 million in net proceeds from our December 2008 Senior Notes offering. We believe that the size and scope of our operations, our stable asset base and cash flow profile and our investment grade status will be significant positive factors in our efforts to obtain new debt or equity funding; however, there is no assurance that we will continue to be successful in obtaining financing under any of the alternatives discussed above if capital markets deteriorate further from current conditions. Furthermore, the terms, size and cost of any one of these financing alternatives could be less favorable and could be impacted by the timing and magnitude of our funding requirements, market conditions and other uncertainties.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas and NGLs have fallen dramatically since July 2008. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our customers to decrease drilling levels and, in some cases, to shut in or consider shutting in natural gas production from some producing wells.

In our intrastate and interstate natural gas operations, a significant portion of our revenue is derived from long-term fee-based arrangements pursuant to which our customers pay us capacity reservation charges regardless of the volume of natural gas transported; however, a portion of our revenue is derived from charges based on actual volumes transported in addition to the excess of fuel retention charged to our customers after consumption. As a result, our operating cash flows from our natural gas pipeline operations are not tied directly to natural gas and NGL prices; however, the volumes of natural gas we transport may be adversely affected by reduced drilling activity of our customers, as well as shut in of production from producing wells, as a result of lower natural gas prices. As a portion of our pipeline transportation revenue is based on volumes transported and fuel retention, lower volumes of natural gas transported and lower natural gas prices generally result in lower revenue from our intrastate and interstate natural gas operations. During the first six months of 2009, natural gas spot prices have ranged from $3.09 per MMbtu to $5.25 per MMbtu, and the closing price on the New York Mercantile Exchange on August 7, 2009 for natural gas to be delivered in September 2009 was $3.67 per MMbtu. As a result, drilling activity in our core operating areas has declined and natural gas producers have shut in production from some wells, which in turn has resulted in lower than expected natural gas volumes transported on our intrastate and interstate pipelines. There are no assurances that commodity prices will not decline further, which could result in a further reduction in drilling activities by our customers.

Since certain of our natural gas marketing operations and substantially all of our propane operations involve the purchase and resale of natural gas and NGLs, we expect our revenues and costs of products sold to be lower than prior periods if commodity prices remain at or fall below existing levels. However, we do not expect our margins from these activities to be significantly impacted as we typically purchase the commodity at a lower price than the sales price. Since the prices of natural gas and NGLs have been volatile, there are no assurances that we will ultimately sell the commodity for a profit.

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swaps where applicable, and to date have not had any significant credit losses associated with our transactions. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Results of Operations

Consolidated Results

	Three Months Ended June 30, 2009	2008	Change	Six Months Ended June 30, 2009	2008	Change
Revenues	$ 1,151,817	$ 2,653,476	$ (1,501,659)	$ 2,781,917	$ 5,292,847	$ (2,510,930)
Cost of products sold	625,993	2,124,072	(1,498,079)	1,585,132	4,103,790	(2,518,658)
Gross margin	525,824	529,404	(3,580)	1,196,785	1,189,057	7,728
Operating expenses	176,681	197,143	(20,462)	358,454	376,113	(17,659)
Depreciation and amortization	76,174	62,421	13,753	148,777	121,249	27,528
Selling, general and administrative	53,749	44,011	9,738	109,481	92,380	17,101
Operating income	219,220	225,829	(6,609)	580,073	599,315	(19,242)
Interest expense, net of interest capitalized	(100,680)	(68,416)	(32,264)	(182,725)	(123,965)	(58,760)
Equity in earnings (losses) of affiliates	1,673	(169)	1,842	2,170	(95)	2,265
Gains (losses) on disposal of assets	181	515	(334)	(245)	(936)	691
Gains (losses) on non-hedged interest rate derivatives	36,842	355	36,487	50,568	(245)	50,813
Allowance for equity funds used during construction	(1,839)	15,660	(17,499)	18,588	25,548	(6,960)
Other, net	(100)	1,942	(2,042)	967	10,291	(9,324)
Income tax expense	(4,559)	(10,042)	5,483	(11,491)	(15,904)	4,413
Net income	$ 150,738	$ 165,674	$ (14,936)	$ 457,905	$ 494,009	$ (36,104)

See the detailed discussion of revenues, costs of products sold, margin and operating expense by operating segment below.

Interest Expense. Interest expense increased principally due to higher levels of borrowings which were used to finance growth capital expenditures primarily in our intrastate transportation and storage and interstate transportation segments.

Gains (Losses) on Non-Hedged Interest Rate Derivatives. We recorded unrealized gains on our floating-to-fixed interest rate swaps as a result of increases in the relevant floating index rates during the three and six months ended June 30, 2009.

Allowance for Equity Funds Used During Construction. The decrease in AFUDC on equity was due to the completion of the Phoenix project in February 2009.

Other Income, Net. The decrease between the six month periods was primarily due to contributions in aid of construction, which exceeded our project costs during the six months ended June 30, 2008.

Income Tax Expense. The decrease in income tax expense between the periods was primarily due to decreases in taxable income within our subsidiaries that are taxable corporations.

Segment Operating Results

We evaluate segment performance based on operating income, 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 our previous fiscal year ended December 31, 2008 filed with the SEC on March 2, 2009.

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Operating income by segment is as follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Change	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Change
Intrastate transportation and storage	$ 156,929	$ 136,370	$ 20,559	$ 300,644	$ 324,218	$ (23,574)
Interstate transportation	31,950	28,491	3,459	60,145	57,717	2,428
Midstream	28,050	65,269	(37,219)	53,189	117,655	(64,466)
Retail propane and other retail propane related	4,560	(5,523)	10,083	168,629	101,432	67,197
Other	(1,016)	(336)	(680)	(1,782)	(341)	(1,441)
Unallocated selling, general and administrative expenses	(1,253)	1,558	(2,811)	(752)	(1,366)	614
Operating income	$ 219,220	$ 225,829	$ (6,609)	$ 580,073	$ 599,315	$ (19,242)

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses are allocated monthly to the Operating Partnerships using the Modified Massachusetts Formula Calculation. The expenses subject to allocation are based on estimated amounts and take into consideration 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, 2009	Three Months Ended June 30, 2008	Change	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Change
Natural gas MMBtu/d - transported	13,593,471	10,355,466	3,238,005	13,611,768	9,938,323	3,673,445
Natural gas MMBtu/d - sold	812,193	1,582,022	(769,829)	876,506	1,639,467	(762,961)
Revenues	$ 493,934	$ 1,872,245	$ (1,378,311)	$ 1,122,585	$ 3,353,086	$ (2,230,501)
Cost of products sold	233,951	1,614,660	(1,380,709)	616,565	2,815,132	(2,198,567)
Gross margin	259,983	257,585	2,398	506,020	537,954	(31,934)
Operating expenses	56,918	82,080	(25,162)	110,408	140,695	(30,287)
Depreciation and amortization	25,859	20,022	5,837	50,892	36,473	14,419
Selling, general and administrative	20,277	19,113	1,164	44,076	36,568	7,508
Segment operating income	$ 156,929	$ 136,370	$ 20,559	$ 300,644	$ 324,218	$ (23,574)

Gross Margin.

Three Months

Intrastate transportation and storage gross margin increased between the three month periods primarily due to the following factors:

Transportation fees increased approximately $36.4 million primarily due to increased volumes through our transportation pipelines. Overall volumes on our transportation pipelines were higher principally due to increased capacity of our pipeline system as a result of the completion of the Paris Loop, Maypearl to Malone pipeline, Carthage Loop, Southern Shale pipeline, Cleburne to Tolar pipeline and the Katy expansion during 2008 and 2009.

Our fuel retention revenues are directly impacted by changes in natural gas prices and volumes. Increases in natural gas prices increase our fuel retention revenues and decreases in natural gas prices decrease our fuel retention revenues. Due to the increased transportation volumes discussed above, fuel retention revenues increased approximately $19.3 million compared to the prior period. Natural gas prices for retained fuel decreased from an average of $10.13/MMBtu during the three months ended June 30, 2008 to $3.26/MMBtu during the three months ended June 30, 2009 resulting in a decrease to the retention margin of $76.5 million.

We experienced a net increase in storage margin of $48.5 million. During the three months ended June 30, 2008, we recognized $10.3 million of losses due to the discontinuation of hedge accounting and $21.3 million of derivative losses related to planned withdrawals from our Bammel storage facility that did not occur.

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Beginning in April 2009, we elected fair value hedge accounting for certain storage-related transactions. As a result of the election, we recognized $12.5 million in unrealized gains during the three months ended June 30, 2009 due to favorable changes in the relationship between the hedged inventory and the related hedged derivative instrument. We also recognized approximately $2.8 million of gains during the current period primarily due to storage-related derivatives not designated as hedges. Fee-based storage revenue also increased our margin by $1.6 million as compared to the prior period.

In addition to the above factors, we experienced a reduction in margin of $18.9 million as compared to the prior period principally due to lower natural gas prices, less favorable processing conditions and lower demand from industrial end users and local distribution companies. Additionally, we experienced a net decrease in margin of $9.1 million primarily related to less favorable market conditions between the Waha and Katy/Houston Ship Channel market hubs and east Texas markets.

Six Months

Intrastate transportation and storage gross margin decreased between the six month periods primarily due to the following factors:

Transportation fees increased approximately $93.4 million primarily due to increased volumes through our transportation pipelines. Overall volumes on our transportation pipelines were higher principally due to increased capacity of our pipeline system as a result of the completion of the Paris Loop, Maypearl to Malone pipeline, Carthage Loop, Southern Shale pipeline, Cleburne to Tolar pipeline and the Katy expansion during 2008 and 2009.

As mentioned above, our fuel retention revenues are directly impacted by changes in natural gas prices and volumes. Due to the increased transportation volumes discussed above, fuel retention revenues increased approximately $39.9 million compared to the prior period. Natural gas prices for retained fuel decreased from an average of $8.93/MMBtu during the six months ended June 30, 2008 to $3.37/MMBtu during the six months ended June 30, 2009 resulting in a decrease to the retention margin of $123.9 million.

We experienced a net increase in storage margin of $2.6 million. Several factors contributed to the change. During the six months ended June 30, 2008, we recognized $10.3 million of losses due to the discontinuation of hedge accounting and $21.3 million of derivative losses related to planned withdrawals from our Bammel storage facility that did not occur. We also recognized $52.8 million of margin related to 36 Bcf of natural gas sold during the six months ended June 30, 2008. During the six months ended June 30, 2009, we withdrew 11.3 Bcf of natural gas from our Bammel storage facility for a margin of $10.5 million, which included a $44.6 million non-cash lower of cost or market write-down of our natural gas inventory. Beginning in April 2009, we elected fair value hedge accounting for certain storage-related transactions. As a result of the election, we recognized $12.5 million in unrealized gains during the six months ended June 30, 2009 due to favorable changes in the relationship between the hedged inventory and the related hedged derivative instrument. Fee-based storage revenue also increased our margin by $0.5 million as compared to the prior period.

In addition to the above factors, we experienced a reduction in margin of $31.8 million as compared to the prior period principally due to lower natural gas prices, less favorable processing conditions and lower demand from industrial end users and local distribution companies. Additionally, we experienced a net decrease in margin of $15.8 million as compared to the prior period primarily related to unfavorable market conditions between the Waha and Katy/Houston Ship Channel market hubs and east Texas markets.

Operating Expenses.

Three Months

Intrastate transportation and storage operating expenses decreased between the three month periods primarily due to a decrease in consumption expense of $30.2 million, which was principally caused by lower natural gas prices between periods, and a decrease in electricity costs of approximately $2.5 million. Offsetting the decrease was an increase in ad valorem taxes of $3.3 million and increased pipeline maintenance expenses of $3.8 million.

Six Months

Intrastate transportation and storage operating expenses decreased between the six month periods primarily due to a decrease in consumption expense of $46.6 million, which was principally caused by lower natural gas prices between periods. Offsetting the decrease were increases in ad valorem taxes of $13.1 million and pipeline maintenance expenses of $4.5 million.

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Depreciation and Amortization.

Three Months

Intrastate transportation and storage depreciation and amortization expense increased between the three month periods primarily due to the completion of pipeline expansion projects.

Six Months

Intrastate transportation and storage depreciation and amortization expense increased between the six month periods primarily due to the completion of pipeline expansion projects.

Selling, General and Administrative.

Three Months

Intrastate transportation and storage selling, general and administrative expenses increased between the three month periods primarily due to an increase in professional fees of $1.3 million.

Six Months

Intrastate transportation and storage selling, general and administrative expenses increased between the six month periods primarily due to increased employee-related expenses (including allocated overhead expenses) of approximately $2.2 million and increased professional fees of $5.3 million.

Interstate Transportation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Change	2009	2008	Change
Natural gas MMBtu/d - transported	1,683,298	1,768,406	(85,108)	1,715,252	1,693,882	21,370
Natural gas MMBtu/d - sold	24,294	13,396	10,898	19,695	12,240	7,455
Revenues	$ 70,585	$ 59,224	$ 11,361	$ 131,934	$ 114,640	$ 17,294
Operating expenses	17,344	14,630	2,714	32,709	25,850	6,859
Depreciation and amortization	12,837	9,266	3,571	23,496	18,566	4,930
Selling, general and administrative	8,454	6,837	1,617	15,584	12,507	3,077
Segment operating income	$ 31,950	$ 28,491	$ 3,459	$ 60,145	$ 57,717	$ 2,428

Revenues.

Three Months

Interstate revenues increased between the three month periods by approximately $15.1 million primarily as a result of the completion of the San Juan Lateral in July 2008 and the completion of the Phoenix project in February 2009, offset by a $3.7 million decrease in operational sales primarily due to decreased natural gas prices between the periods. Transported volumes decreased as compared to the prior period primarily as a result of less favorable spreads between the San Juan and Permian Basins during the three months ended June 30, 2009.

Six Months

Interstate revenues increased between the six month periods by approximately $24.5 million due to increased transported natural gas volumes primarily as a result of the completion of the San Juan Lateral in July 2008 and the completion of the Phoenix project in February 2009, offset by a $7.2 million decrease in operational sales primarily due to decreased natural gas prices between the periods.

Operating Expenses.

Three Months

Interstate operating expenses increased between the three month periods primarily due to an increase in ad valorem taxes of approximately $1.0 million resulting from increased property values, and a net increase in other operating expenses of $1.7 million primarily due to pipeline expansions as noted above.

Six Months

Interstate operating expenses increased between the six month period primarily due to an increase in ad valorem taxes of approximately $3.9 million resulting from increased property values, an increase of $1.5 million due to higher electric usage required by the increased transportation volumes, and a net increase in other expenses of $1.4 million primarily due to pipeline expansions as noted above.

Depreciation and Amortization.

Three months

Interstate depreciation and amortization expense increased between the three month periods primarily due to incremental depreciation associated with the completion of the San Juan Lateral and Phoenix projects.

Six Months

Interstate depreciation and amortization expense increased between the six month periods primarily due to incremental depreciation associated with the completion of the San Juan Lateral and Phoenix projects.

Selling, General and Administrative.

Three Months

Interstate selling, general and administrative expenses increased between the three month periods primarily due to an increase in employee-related costs.

Six Months

Interstate selling, general and administrative expenses increased between the six month periods due to an increase allocated overhead expenses and professional fees of approximately $1.2 million, with the remainder of the increase being primarily attributed to an increase in employee-related costs.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Change	2009	2008	Change
Natural gas MMBtu/d - sold	916,048	1,518,209	(602,161)	1,003,236	1,377,495	(374,259)
NGLs Bbls/d - sold	41,338	28,097	13,241	40,781	29,590	11,191
Revenues	$ 545,768	$ 1,874,420	$ (1,328,652)	$ 1,177,400	$ 3,120,184	$ (1,942,784)
Cost of products sold	470,108	1,768,161	(1,298,053)	1,029,284	2,919,131	(1,889,847)
Gross margin	75,660	106,259	(30,599)	148,116	201,053	(52,937)
Operating expenses	17,011	17,253	(242)	34,804	34,131	673
Depreciation and amortization	17,191	13,489	3,702	33,701	27,335	6,366
Selling, general and administrative	13,408	10,248	3,160	26,422	21,932	4,490
Segment operating income	$ 28,050	$ 65,269	$ (37,219)	$ 53,189	$ 117,655	$ (64,466)

Gross Margin.

Three Months

Midstream gross margin decreased between the three month periods primarily due to a decrease in processing margin of approximately $25.4 million principally due to less favorable processing conditions. However, margins from our fee-based revenue remained consistent with the prior period. The increase in NGL volumes sold was principally due to increased capacity to deliver NGL volumes at our Godley plant starting in January 2009. Additionally, gross margin decreased approximately $5.1 million between the three month periods primarily due to a decrease in the volumes of natural gas sold as a result of less favorable market conditions during the 2009 period.

Six Months

Midstream gross margin decreased between the six month periods primarily due to a decrease in processing margin of $60.0 million offset by an increase in fee-based revenue of $7.1 million. The increase from our fee-based revenue was primarily due to our Canyon pipeline assets and the increase in NGL take-away capacity at our Godley plant allowing us to charge additional processing fees. The decrease in processing margins was primarily due to less favorable processing conditions in the 2009 period. The increase in NGL volumes sold was due to increased capacity to deliver NGL volumes at our Godley plant starting in January 2009 and the decrease in the volumes of natural gas sold was primarily due to less favorable market conditions as compared to the prior period.

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Operating Expenses.

Three Months

Midstream operating expenses decreased between the three month periods primarily due to a decrease in compressor and related expenses of $0.5 million offset by a net increase in other operating expenses of $0.3 million.

Six Months

Midstream operating expenses increased between the six month periods primarily due to an increase in ad valorem taxes of $1.9 million and electricity expenses of $1.1 million. These increases were offset by a decrease in compressor related expenses of $1.9 million and a net decrease of approximately $0.4 million in other operating expenses.

Depreciation and Amortization.

Three Months

Midstream depreciation and amortization expense increased between the three month periods primarily due to incremental depreciation from the continued expansion of our Godley plant.

Six Months

Midstream depreciation and amortization expense increased between the six month periods primarily due to incremental depreciation from the continued expansion of our Godley plant.

Selling, General and Administrative.

Three Months

Midstream selling, general and administrative expenses increased between the three month periods primarily due to increased professional fees of $3.3 million offset by a net decrease in other expenses of approximately $0.1 million.

Six Months

Midstream selling, general and administrative expenses increased between the six month periods primarily due to an increase in professional fees of $4.7 million and a net increase of approximately $1.0 million in other expenses. This increase was offset by a net decrease in employee related expenses (including allocated overhead expenses) of approximately $1.2 million.

Retail Propane and Other Retail Propane Related

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	**2008**	**Change**	**2009**	**2008**	**Change**
Retail propane gallons (in thousands)	92,153	97,309	(5,156)	310,633	331,723	(21,090)
Retail propane revenues	$ 179,770	$ 249,449	$ (69,679)	$ 667,677	$ 847,587	$ (179,910)
Other retail propane related revenues	22,502	24,211	(1,709)	50,507	51,788	(1,281)
Retail propane cost of products sold	78,070	163,962	(85,892)	298,292	556,517	(258,225)
Other retail propane related cost of products sold	4,816	4,320	496	9,699	9,496	203
Gross margin	119,386	105,378	14,008	410,193	333,362	76,831
Operating expenses	84,294	82,043	2,251	178,470	173,350	5,120

Depreciation and amortization	20,174	19,487	687	40,446	38,573	1,873
Selling, general and administrative	10,358	9,371	987	22,648	20,007	2,641
Segment operating income (loss)	$ 4,560	$ (5,523)	$ 10,083	$ 168,629	$ 101,432	$ 67,197

Volumes.

Retail propane volumes decreased primarily due to the continued effects of customer conservation, by the impact of the economic recession and, to a lesser extent, the decline in new home construction. Volumes also decreased due to weather that was approximately 2% and 7% warmer during the three and six months ended June 30, 2009 as compared to the same periods in 2008. These decreases were partially offset by the volume increases from acquisitions made since June 30, 2008.

Gross Margin.

Three Months

Total gross margin increased between the three month periods primarily due to our ability to maintain a slower pace of decreasing selling prices despite a significant decrease in the wholesale market price of propane. Our average cost per gallon of propane was approximately 50.4% lower during the three months ended June 30, 2009 as compared to the three months ended June 30, 2008. Gross margins were also favorably impacted by a net change of $6.7 million in realized gains related to the settlement of mark-to-market contracts during the three months ended June 30, 2009. These net realized gains were partially offset by a net change of $1.8 million in unrealized losses from mark-to-market accounting for our financial instruments. The three months ended June 30, 2009 excludes $1.3 million of net unrealized gains recorded in Accumulated Other Comprehensive Income (AOCI) as a result of designation of cash flow hedging relationships in April 2009, which will be recognized in the condensed consolidated statements of operations when the forward or forecasted propane sales transaction occurs.

Six Months

Total gross margin increased between the six month periods primarily due to our ability to maintain a slower pace of decreasing selling prices despite a significant decrease in the wholesale market price of propane and the impact of mark-to-market accounting of our financial instruments. Our average cost per gallon of propane was approximately 43.4% lower during the six months ended June 30, 2009. To hedge a significant portion of our propane sales commitments, we utilize financial instruments as purchase commitments to lock in the margins. Prior to April 2009, these financial instruments were not designated as hedges for accounting purposes, and changes in market value were recorded in cost of products sold in the condensed consolidated statements of operations. During the six months ended June 30, 2009, our propane margins were positively impacted by sales made to retail customers with whom we had previously entered into sales commitments, while the settlement of financial instruments related to those sales resulted in the realization of $41.6 million of losses that had previously been recognized in 2008. The six months ended June 30, 2009 excludes $1.3 million of net unrealized gains recorded in AOCI as a result of designation of cash flow hedging relationships in April 2009, which will be recognized in the condensed consolidated statements of operations when the forward or forecasted propane sales transaction occurs.

Operating Expenses.

Three Months

The primary factors that affected our operating expenses for the three months ended June 30, 2009 were an increase in our operational employee incentive program of $2.1 million, an increase in employee wages and benefits of $2.0 million due to more favorable results achieved during the three months ended June 30, 2009 as compared to the prior period and an increase related to additional employees from acquisitions completed after June 30, 2008. Propane operating expenses also increased slightly due to the additional operating expenses from acquisitions made since June 30, 2008; however, these increases were offset by cost control initiatives from our operations and by a decrease of $3.4 million in the vehicle fuel used for delivery to customers due to the significant decline in fuel prices between the periods.

Six Months

The primary factors that affected our operating expenses for the six months ended June 30, 2009 were an increase in our operational employee incentive program of $8.2 million, an increase in employee wages and benefits of $4.2 million due to more favorable results achieved during the six months ended June 30, 2009 as compared to the prior period and an increase related to additional employees from acquisitions completed after June 30, 2008. Propane operating expenses also increased slightly due to the additional operating expenses from acquisitions made since June 30, 2008; however, these increases were largely offset by cost control initiatives from our operations and by a decrease of $6.3 million in the vehicle fuel used for delivery to customers due to the significant decline in fuel prices between the periods.

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Depreciation and Amortization Expense.

The increase in depreciation and amortization expense for both the three and six month periods was primarily related to assets added through acquisitions made after June 30, 2008.

Selling, General and Administrative Expenses.

The increase in selling, general and administrative expenses between comparable periods was primarily due to increased administrative expense allocations of $1.3 million and $3.5 million for the three and six month periods, respectively, offset by the reduction in other non-recurring expenses incurred during the prior 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 $100.0 million and $120.0 million during the last six months of 2009;

- growth capital expenditures for our interstate transportation segment, excluding capital contributions to the MEP and FEP projects as discussed below, for the construction of new pipelines and pipeline expansions for our interstate operations, for which we expect to spend between $140.0 million and $160.0 million during the last six months of 2009;

- capital contributions to MEP and FEP as follows:

  - With respect to MEP, capital expenditures were previously funded under a $1.4 billion credit facility at MEP (reduced to $1.3 billion due to the bankruptcy of Lehman Brothers); however, as this facility became substantially drawn during the first quarter of 2009, we and KMP have made and will continue to make capital contributions to MEP to fund capital expenditures until the project is completed. We expect that our capital contributions to MEP during the last six months of 2009 will be between $320.0 million and $340.0 million, which includes amounts to fund remaining expenditures for the project and an additional capital contribution to reduce the indebtedness of MEP to a level expected to be needed to obtain long-term financing for MEP, on a stand-alone basis without guarantees from ETP or KMP, on acceptable terms.

  - With respect to FEP, we expect that our capital contributions will be between $160.0 million and $180.0 million during the last six months of 2009 to fund expenditures for the project. FEP intends to pursue financing (expected to be severally guaranteed by ETP and KMP), which, if arranged during the last six months of 2009, would reduce the level of expected capital contributions this year as capital expenditures for the project would be funded at the project level; however, the availability of such financing at agreeable terms remains uncertain.

- growth capital expenditures for our retail propane segment of between $10.0 million and $20.0 million during the last six months of 2009;

- maintenance capital expenditures of between $50.0 million and $60.0 million during the last six months of 2009; and 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.

In light of the current conditions in the capital markets, and based on our projected growth capital expenditures and capital contributions to joint venture entities, we have taken significant steps to preserve our liquidity position including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate at $3.575 per Common Unit on an annualized basis since the second quarter of 2008, and continuing to appropriately manage operating and administrative costs. During the six months ended June 30, 2009, we received approximately $578.3 million in net proceeds from our January 2009 and April 2009 Common Units offerings and $993.6 million in net proceeds from an offering of $1.0 billion of aggregate principal amount of senior notes in April 2009. As of June 30, 2009, in addition to approximately $114.2 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.94 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 without the need to access the capital markets until the latter half 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 or other partnership purposes.

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures other than those expenditures necessary to maintain the service capacity of our existing assets. The assets utilized in our propane operations do not typically require lengthy manufacturing process time or complicated, high technology components. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors into our anticipated growth capital expenditures for each year.

Cash Flows

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

Operating Activities ***Six months ended June 30, 2009 as compared to the six months ended June 30, 2008.*** Cash provided by operating activities during 2009 was $702.7 million as compared to $764.0 million for 2008. Net income was $457.9 million and $494.0 million for 2009 and 2008, respectively. The difference between net income and the net cash provided by operating activities consisted of primarily non-cash activity of $161.1 million and $118.8 million and changes in operating assets and liabilities of $85.0 million and $151.2 million for 2009 and 2008, respectively.

The non-cash activity in 2009 and 2008 consisted primarily of depreciation and amortization of $148.8 million and $121.2 million, respectively. In addition, non-cash compensation expense was $15.1 million and $12.6 million for 2009 and 2008, respectively. These amounts are partially offset by the allowance for equity funds used during construction of $18.6 million and $25.5 million for 2009 and 2008, respectively.

Various factors affect the changes in operating assets and liabilities, such as the timing of accounts receivable collections, payments on accounts payable, the timing of the purchase and sale of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Investing Activities ***Six months ended June 30, 2009 as compared to the six months ended June 30, 2008.*** Cash used in investing activities during 2009 was $875.5 million as compared to $912.4 million for 2008. Total 2009 capital expenditures (excluding the allowance for equity funds used during construction) were $512.5 million, including changes in accruals of $66.0 million. This compares to total 2008 capital expenditures (excluding the allowance for equity funds used during construction) of $978.7 million, including changes in accruals of $151.7 million. In addition, in 2009 we made advances to our joint ventures of $364.0 million. In 2008, we paid $56.8 million in cash for acquisitions. These amounts were offset by a $63.5 million net reimbursement during the first quarter of 2008 from MEP to the Partnership for previous advances to MEP.

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 of maintenance capital 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.

Growth capital expenditures for 2008, before changes in accruals, were $632.6 million for our midstream and intrastate transportation and storage segments, $422.9 million for our interstate transportation segment, and $24.2 million for our retail propane segment and all other. We also incurred $50.6 million in maintenance expenditures, of which $29.1 million related to our midstream and intrastate transportation and storage segments, $6.6 million related to our interstate transportation segment and $14.9 million related to our retail propane segment.

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Financing Activities Six months ended June 30, 2009 as compared to the six months ended June 30, 2008. Cash provided by financing activities during 2009 was $195.2 million as compared to $150.5 million for 2008. In 2009, we received $578.9 million in net proceeds from Common Unit offerings as compared to $35.0 million in 2008 (see Note 13 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 and to fund capital contributions to joint ventures related to pipeline construction projects. During 2009, we had a net increase in our debt level of $86.5 million as compared to a net increase in our debt level of $583.9 million for 2008. In addition, we paid distributions of $465.8 million to our partners in 2009 as compared to $447.4 million in 2008.

In 2009, the net increase in debt was primarily due to borrowings to fund capital expenditures and to fund capital contributions to joint ventures, partially offset by the use of proceeds from our Common Unit offerings. We also issued Senior Notes (see Note 12 to our condensed consolidated financial statements) for net proceeds of $993.6 million which were used to repay outstanding borrowings under the ETP Credit Facility and for general partnership purposes.

In 2008, we received $1.48 billion in net proceeds from the issuance of Senior Notes, which were used to repay principal and interest on our credit facilities, to fund our growth capital expenditures and for general partnership purposes.

Financing and Sources of Liquidity

In January 2009, we issued 6,900,000 Common Units representing limited partner interests at $34.05 per Common Unit in a public offering. Net proceeds of approximately $225.9 million from the offering were used to repay outstanding borrowings under the ETP Credit Facility.

In April 2009, we completed the issuance of $350.0 million aggregate principal amount of 8.50% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.00% Senior Notes due 2019. We used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes.

In April 2009, we also issued 9,775,000 Common Units representing limited partner interests at $37.55 per Common Unit in a public offering. The proceeds of approximately $352.4 million, net of underwriting discounts and commissions, were used to fund capital expenditures and capital contributions to joint venture entities related to pipeline construction projects as well as for general partnership purposes.

Description of Indebtedness

Our outstanding indebtedness was as follows:

	June 30, 2009	December 31, 2008
ETP Senior Notes	$ 5,050,000	$ 4,050,000
Transwestern Senior Unsecured Notes	520,000	520,000
HOLP Senior Secured Notes	168,684	181,410
Revolving Credit Facilities		912,000
Other long-term debt	11,525	13,814
Unamortized discounts	(13,176)	(13,477)
Total Debt	$ 5,737,033	$ 5,663,747

The terms of our indebtedness and that of our Operating Partnerships are described in more detail in our Annual Report on Form 10-K as of December 31, 2008, filed with the SEC on March 2, 2009.

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

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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 indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating; the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of June 30, 2009, there was no balance outstanding on the ETP Credit Facility and taking into account letters of credit of approximately $59.8 million, $1.94 billion was available for future borrowings.

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. There were outstanding letters of credit of $1.0 million on the HOLP Credit Facility at June 30, 2009. The amount available as of June 30, 2009 was $74.0 million.

Other

We have guaranteed 50% of the obligations of MEP under its $1.4 billion senior revolving credit facility (the MEP Facility), with the remaining 50% of the MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage of MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. The MEP Facility is syndicated among multiple financial institutions. As a result of the Lehman Brothers bankruptcy in 2008, the MEP Facility has effectively been reduced by the Lehman Brothers affiliate s commitment of approximately $100.0 million. However, the MEP Facility is not in default, and the commitments of the other lending banks remain unchanged.

As of June 30, 2009, MEP had $1.19 billion of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP s outstanding borrowings and letters of credit were $595.4 million and $16.6 million, respectively, as of June 30, 2009.

Cash Distributions

We use cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders as well as to our General Partner in respect of its 2% general partner interest and its Incentive Distribution Rights (IDRs). Under the Partnership Agreement, we will distribute to our partners within 45 days after the end of each fiscal quarter, an amount equal to all of our Available Cash 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 General Partner s IDRs entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis).

On February 13, 2009, we paid a per unit cash distribution related to the three months ended December 31, 2008 of $0.89375 per Common Unit ($3.575 per Limited Partner Unit annualized) to Unitholders of record at the close of business on February 6, 2009. On May 15, 2009, we paid a per unit cash distribution related to the three months ended March 31, 2009 of $0.89375 per Common Unit ($3.575 per Limited Partner Unit annualized) to Unitholders of record at the close of business on May 8, 2009. We paid $172.9 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its Incentive Distribution Rights.

On July 28, 2009, we declared a cash distribution for the three months ended June 30, 2009 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 14, 2009 to Unitholders of record at the close of business on August 7, 2009.

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New Accounting Standards

See Note 2 to our condensed consolidated financial statements.

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, 2008, 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. Since December 31, 2008, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

Our commodity-related price risk management assets and liabilities as of June 30, 2009 were as follows:

	Commodity	Notional Volume	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	50,700,000	2009-2011	$ 3,001
Swing Swaps IFERC (MMBtu)	Gas	(44,095,000)	2009-2010	4,562
Fixed Swaps/Futures (MMBtu)	Gas	4,567,500	2009-2011	3,592
Forwards/Swaps (Gallons)	Propane/Ethane	15,078,000	2009-2010	933
Fair Value Hedging Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	(31,117,500)	2009-2010	$ (1,975)
Fixed Swaps/Futures (MMBtu)	Gas	(31,990,000)	2009-2010	(589)
Cash Flow Hedging Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Gas	460,000	2009	$ 7
Fixed Swaps/Futures (MMBtu)	Gas	460,000	2009	(1,549)
Forward/Swaps (Gallons)	Propane/Ethane	18,858,000	2009-2010	1,315

Credit Risk

We maintain credit policies with regard to our counterparties that we believe significantly minimize 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. 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 sheets and recognized in net income or other comprehensive income. For additional discussion of our credit risks, see the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2008.

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Sensitivity Analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of June 30, 2009, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity.

	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark to Market Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	50,700,000	$ 3,001	$ 1,426
Swing Swaps IFERC (MMBtu)	(44,095,000)	4,562	656
Fixed Swaps/Futures (MMBtu)	4,567,500	3,592	1,917
Propane Forwards/Swaps (Gallons)	15,078,000	933	1,293
Fair Value Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	(31,117,500)	$ (1,975)	$ 693
Fixed Swaps/Futures (MMBtu)	(31,990,000)	(589)	14,998
Cash Flow Hedging Derivatives			
Basis Swaps IFERC/NYMEX (MMBtu)	460,000	$ 7	$ 202
Fixed Swaps/Futures (MMBtu)	460,000	(1,549)	10
Forwards/Swaps, Forecasted purchase of propane (Gallons)	18,858,000	1,315	1,632

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 accumulated 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

We are exposed to market risk for increases in interest rates, primarily as a result of our revolving credit facilities, which have variable interest rates, and our interest rate swaps. To the extent interest rates increase, our interest expense under these revolving credit facilities will increase. At June 30, 2009, we had forward starting interest rate swaps with a notional amount of $500.0 million not designated as hedges under SFAS 133. A hypothetical change of 100 basis points in the underlying interest rate and a corresponding parallel shift in the LIBOR yield curve would have a net effect of approximately $41.0 million in gains (losses) on non-hedged interest rate derivatives on an annual basis.

We are also subject to interest rate risk on our fixed rate debt if interest rates decrease. To manage this risk, we may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt. For further information, see Note 16 to our condensed consolidated financial statements.

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ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of senior management, including the Chief Executive Officer (Principal Executive Officer) and the Chief Financial Officer (Principal Financial Officer) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a 15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of June 30, 2009 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, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for our previous year ended December 31, 2008 and Note 15 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 Form 10-Q for the six months ended June 30, 2009.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2008.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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
(1)	3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(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.

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	Exhibit Number	Description
(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.
(8)	4.18	Eighth Supplemental Indenture dated as of April 7, 2009 to Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(*)	10.1	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers party thereto.
(*)	10.2	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(*)	10.3	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(*)	10.4	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(*)	10.5	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers party thereto.
(*)	10.6	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.
(*)	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.

* 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 Exhibit 4.2 to the Registrant s Form 8-K filed April 9, 2009.

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SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P.,

its General Partner

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

Date: August 10, 2009

By: /s/ Martin Salinas, Jr.
Martin Salinas, Jr.
(Chief Financial Officer duly authorized to sign on

behalf of the registrant)

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