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

FORM 10-Q

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

For the quarterly period ended September 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 November 5, 2009, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.   175,773,593 Common Units

FORM 10-Q

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. ("Energy Transfer Partners" or "the Partnership") in periodic press releases and some oral statements of Energy Transfer Partners officials during presentations about the Partnership, include certain "forward-looking" statements 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. Although the Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that 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 for the year ended 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.

Table of Contents

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)
(unaudited)

	September 30, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 50,059	$ 91,902
Marketable securities	12,682	5,915
Accounts receivable, net of allowance for doubtful accounts	352,838	591,257
Accounts receivable from related companies	35,972	17,895
Inventories	221,148	272,348
Deposits paid to vendors	99,317	78,237
Exchanges receivable	15,434	45,209
Price risk management assets	6,841	5,423
Prepaid expenses and other current assets	67,680	75,215
Total current assets	861,971	1,183,401
PROPERTY, PLANT AND EQUIPMENT	9,616,309	8,996,911
ACCUMULATED DEPRECIATION	(905,624)	(700,826)
	8,710,685	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	550,950	10,110
GOODWILL	736,347	743,694
INTANGIBLES AND OTHER ASSETS, net	394,767	394,199
Total assets	$ 11,254,720	$ 10,627,489

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	September 30, 2009	December 31, 2008
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 253,892	$ 381,135
Accounts payable to related companies	7,591	34,547
Exchanges payable	22,400	54,636
Customer advances and deposits	101,258	106,679
Accrued and other current liabilities	247,466	311,988
Price risk management liabilities	18,279	94,978
Interest payable	110,744	106,259
Income taxes payable	5,481	14,538
Deferred income taxes	-	589
Current maturities of long-term debt	46,078	45,198
Total current liabilities	813,189	1,150,547
LONG-TERM DEBT, less current maturities	6,166,083	5,618,549
DEFERRED INCOME TAXES	105,156	100,597
OTHER NON-CURRENT LIABILITIES	21,076	14,727
COMMITMENTS AND CONTINGENCIES (Note 15)		
	7,105,504	6,884,420
PARTNERS' CAPITAL:		
General Partner	169,038	161,159
Limited Partners:		
Common Unitholders (168,834,045 and 152,102,471 units authorized, issued and outstanding at September 30, 2009 and December 31, 2008, respectively)	3,994,530	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)	(14,352)	2,913
Total partners' capital	4,149,216	3,743,069
Total liabilities and partners' capital	$ 11,254,720	$ 10,627,489

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008 As Adjusted (Note 2)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008 As Adjusted (Note 2)
REVENUES:				
Natural gas operations	$ 943,975	$ 1,938,586	$ 3,004,163	$ 6,322,070
Retail propane	162,224	238,830	829,901	1,086,417
Other	23,397	28,799	77,449	90,575
Total revenues	1,129,596	2,206,215	3,911,513	7,499,062
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	591,797	1,435,308	1,865,914	4,965,145
Cost of products sold - retail propane	80,232	187,799	378,524	744,316
Cost of products sold - other	6,119	10,347	18,842	27,783
Operating expenses	158,883	197,493	517,337	573,606
Depreciation and amortization	81,684	70,508	230,461	191,757
Selling, general and administrative	33,534	44,252	143,015	136,632
Total costs and expenses	952,249	1,945,707	3,154,093	6,639,239
OPERATING INCOME	177,347	260,508	757,420	859,823
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(101,503)	(67,792)	(284,228)	(191,757)
Equity in earnings (losses) of affiliates	9,581	(654)	11,751	(749)
Gains (losses) on disposal of assets	(1,088)	2,520	(1,333)	1,584
Gains (losses) on non-hedged interest rate derivatives	(18,241)	394	32,327	149
Allowance for equity funds used during construction	30	19,727	18,618	45,275
Other, net	3,433	(805)	4,400	9,486
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	69,559	213,898	538,955	723,811
Income tax expense (benefit)	(2,897)	(7,150)	8,594	8,754
NET INCOME	72,456	221,048	530,361	715,057
GENERAL PARTNER’S INTEREST IN NET INCOME	88,927	80,252	266,396	233,599
LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS)	$ (16,471)	$ 140,796	$ 263,965	$ 481,458
BASIC NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ (0.10)	$ 0.94	$ 1.60	$ 3.32
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	168,815,563	149,839,499	164,183,538	145,160,079
DILUTED NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ (0.10)	$ 0.94	$ 1.59	$ 3.31
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	168,815,563	150,248,194	164,886,492	145,615,088

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 72,456	$ 221,048	$ 530,361	$ 715,057
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	871	(533)	(8,822)	(13,742)
Change in value of derivative instruments accounted for as cash flow hedges	(15,150)	6,969	(15,200)	(525)
Change in value of available-for-sale securities	3,049	(5,703)	6,757	(2,760)
	(11,230)	733	(17,265)	(17,027)
Comprehensive income	$ 61,226	$ 221,781	$ 513,096	$ 698,030

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

FOR THE NINE MONTHS ENDED SEPTEMBER 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	(261,890)	(443,846)	-	(705,736)
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	-	(2,072)	-	(2,072)
Tax effect of remedial income allocation from tax amortization of goodwill	-	(2,822)	-	(2,822)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	-	20,465	-	20,465
Non-cash executive compensation expense	19	919	-	938
Other comprehensive loss, net of tax	-	-	(17,265)	(17,265)
Net income	266,396	263,965	-	530,361
Balance, September 30, 2009	$ 169,038	$ 3,994,530	$ (14,352)	$4,149,216

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)
(unaudited)

	Nine Months Ended September 30,	
	2009	2008
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 796,017	$ 994,914
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(6,244)	(62,002)
Capital expenditures (excluding allowance for equity funds used during construction)	(703,461)	(1,507,766)
Contributions in aid of construction costs	5,251	46,261
(Advances to) repayments from affiliates, net	(534,500)	63,534
Proceeds from the sale of assets	13,235	20,232
Net cash used in investing activities	(1,225,719)	(1,439,741)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	2,287,035	4,744,414
Principal payments on debt	(1,768,079)	(3,526,971)
Net proceeds from issuance of Limited Partner Units	578,924	373,079
Capital contribution from General Partner	3,354	7,969
Distributions to partners	(705,736)	(663,160)
Debt issuance costs	(7,639)	(20,897)
Net cash provided by financing activities	387,859	914,434
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(41,843)	469,607
CASH AND CASH EQUIVALENTS, beginning of period	91,902	56,467
CASH AND CASH EQUIVALENTS, end of period	$ 50,059	$ 526,074

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

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

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 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 September 30, 2009 and for the three and nine months ended September 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 November 9, 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 September 30, 2009, and the Partnership's results of operations and cash flows for the three and nine months ended September 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 operating subsidiaries (collectively, the "Operating Companies") 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 Companies 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 nine months ended September 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 as discussed further below.

Accounting Standards Codification. On July 1, 2009, the Financial Accounting Standards Board ("FASB") instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The *FASB Accounting Standards Codification*™ ("ASC") is now the single authoritative source for GAAP. Although the implementation of ASC has no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Earnings per Unit. On January 1, 2009, we adopted a new methodology for calculating earnings per unit to reflect recently ratified changes to accounting standards. This new standard was originally issued as Emerging Issues Task Force Issue No. 07-4, (*Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships)* and is now incorporated into ASC 260-10.

Based on the terms of our partnership agreement, the new methodology 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 incentive distribution rights ("IDRs"). Previously, we allocated a portion of the excess undistributed earnings to the IDRs. Thus, for periods where earnings exceed distributions, the new methodology will result in a higher income per limited partner unit than our previous approach. For periods where distributions exceed earnings, the new methodology is consistent with our previous approach.

The following financial table sets forth the effect of the retrospective application of the new methodology under ASC 260-10-55 on income per limited partner unit for the three and nine months ended September 30, 2008:

	Three Months Ended September 30, 2008		Nine Months Ended September 30, 2008	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted
Basic net income per limited partner unit	$ 0.93	$ 0.94	$ 3.06	$ 3.32
Diluted net income per limited partner unit	$ 0.93	$ 0.94	$ 3.05	$ 3.31

On January 1, 2009, we also adopted FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which is now incorporated into ASC 260-10. This standard 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. Based on unvested unit awards outstanding at the time of adoption, application of this standard did not have a material impact on our computation of earnings per unit.

Business Combinations. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations*, which is now incorporated into ASC 805. The new standard significantly changes the accounting for business combinations and includes a substantial number of new disclosure requirements. The new standard requires an acquiring entity to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions and 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.

Our adoption of this standard did not have an immediate impact on our financial position or results of operations; however, it has impacted the accounting for our business combinations subsequent to adoption.

Derivatives Instruments and Hedging Activities. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133,* which is now incorporated into ASC 815. This standard changed the disclosure requirements for derivative instruments and hedging activities, including requirements for 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. The standard only affected disclosure requirements; therefore, our adoption did not impact our financial position or results of operations.

Equity Method Investment Accounting. On January 1, 2009, we adopted Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations*, which is now incorporated into ASC 323-10. This standard 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, and 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 did not have a material impact on our financial condition or results of operations.

Subsequent Events. During 2009, we adopted Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events*, which is now incorporated into ASC 855. Under this standard, we are required to evaluate subsequent events through the date that our financial statements are issued and also required to disclose the date through which subsequent events are evaluated. The adoption of this standard 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.

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

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

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

	Nine Months Ended September 30,	
	2009	2008
Net income	$ 530,361	$ 715,057
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	230,461	191,757
Amortization of finance costs charged to interest	6,386	4,240
Provision for loss on accounts receivable	4,483	4,734
Non-cash unit-based compensation expense	20,942	14,338
Non-cash executive compensation expense	938	937
Deferred income taxes	3,663	(3,781)
(Gains) losses on disposal of assets	1,333	(1,584)
Allowance for equity funds used during construction	(18,618)	(45,275)
Distributions on unvested awards	(2,072)	-
Distributions in excess of (less than) equity in earnings of affiliates, net	(5,696)	4,723
Other non-cash	(450)	-
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	235,239	214,348
Accounts receivable from related companies	(17,882)	(3,063)
Inventories	51,249	58,412
Deposits paid to vendors	(21,080)	(38,328)
Exchanges receivable	29,775	(5,457)
Prepaid expenses and other current assets	10,507	(30,731)
Intangibles and other assets	(1,977)	(14,057)
Accounts payable	(109,479)	(149,801)
Accounts payable to related companies	(27,150)	(10,970)
Exchanges payable	(32,236)	5,047
Customer advances and deposits	(5,566)	63,795
Accrued and other current liabilities	18,818	1,490
Interest payable	4,445	7,699
Income taxes payable	(9,115)	3,655
Other non-current liabilities	669	1,295
Price risk management assets and liabilities, net	(101,931)	6,434
Net cash provided by operating activities	$ 796,017	$ 994,914

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
NON-CASH INVESTING ACTIVITIES:		
Investment in Calpine Corporation received in exchange for accounts receivable	$ -	$ 10,826
Capital expenditures accrued	$ 64,530	$ 195,350
NON-CASH FINANCING ACTIVITIES:		
Capital contribution receivable from general partner	$ 8,932	$ -
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 17,113	$ 4,686
Issuance of Common Units in connection with certain acquisitions	$ -	$ 2,278
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest, net of interest capitalized	$ 288,526	$ 203,578
Cash paid for income taxes	$ 16,527	$ 10,340

4. ACCOUNTS RECEIVABLE:

Accounts receivable consisted of the following:

	September 30, 2009	December 31, 2008
Midstream and intrastate transportation and storage	$ 260,244	$ 415,507
Interstate transportation	29,620	29,309
Propane	71,361	155,191
Less - allowance for doubtful accounts	(8,387)	(8,750)
Total, net	$ 352,838	$ 591,257

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

Balance, December 31, 2008	$ 8,750
Accounts receivable written off, net of recoveries	(4,846)
Provision for loss on accounts receivable	4,483
Balance, September 30, 2009	$ 8,387

5. INVENTORIES:

Inventories consisted of the following:

	September 30, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 115,965	$ 184,727
Propane	45,839	63,967
Appliances, parts and fittings and other	59,344	23,654
Total inventories	$ 221,148	$ 272,348

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, changes in fair value of the designated hedged inventory have been recorded in inventory on our condensed consolidated balance sheet and have been recorded in cost of products sold in our condensed consolidated statement of operations.

Due to the application of fair value hedge accounting for our natural gas inventory, and because certain hedging relationships were designated at points in time where natural gas spot prices were significantly less than our weighted average cost and the spot price as of September 30, 2009, we recorded increases in our natural gas inventory of $9.7 million during the nine months ended September 30, 2009. As a result, our natural gas inventory exceeded the market price at September 30, 2009 after applying fair value hedge accounting, and we therefore recorded a non-cash lower of cost or market adjustment of $9.4 million for the three months ended September 30, 2009. During the nine months ended September 30, 2009, we have recorded lower of cost or market adjustments of $54.0 million in total for our natural gas inventory. No lower of cost or market adjustments were recorded for the nine months ended September 30, 2008.

6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

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

	September 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)	$ 40,219	$ (27,744)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,268	(50,006)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(5,164)	23,015	(3,744)
Other (10 years)	477	(385)	2,677	(2,244)
Total amortizable intangible assets	216,979	(83,299)	210,330	(70,092)
Non-amortizable intangible assets:				
Trademarks	75,503	-	75,667	-
Patents	750	-	-	-
Total non-amortizable intangible assets	76,253	-	75,667	-
Total intangible assets	293,232	(83,299)	285,997	(70,092)
Other long-term assets:				
Financing costs (3 to 30 years)	66,748	(22,638)	59,108	(16,586)
Regulatory assets	105,801	(8,614)	98,560	(5,941)
Other	43,537	-	43,153	-
Total intangibles and other assets	$ 509,318	$ (114,551)	$ 486,818	$ (92,619)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Reported in depreciation and amortization	$ 6,243	$ 4,391	$ 15,935	$ 13,011
Reported in interest expense	$ 2,125	$ 1,590	$ 6,051	$ 4,442

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

Years Ending December 31:	
2010	$ 26,682
2011	25,016
2012	21,431
2013	16,001
2014	14,991

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. We have not completed our annual impairment tests for 2009 and have not recorded any impairments during the nine months ended September 30, 2009. 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 nine months ended September 30, 2009 or 2008.

A net decrease in goodwill of $7.3 million was recorded during the nine months ended September 30, 2009 primarily due to purchase price allocation adjustments related to prior acquisitions of propane businesses.

7. ACCRUED AND OTHER CURRENT LIABILITIES:

Accrued and other current liabilities consisted of the following:

	September 30, 2009	December 31, 2008
Accrued wages and benefits	$ 48,553	$ 64,692
Accrued capital expenditures	64,530	153,230
Taxes other than income taxes	64,531	20,772
Other	69,852	73,294
Total accrued and other current liabilities	$ 247,466	$ 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 the Midcontinent Express pipeline. 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, Midcontinent Express Pipeline, LLC (“MEP”), the entity formed to construct, own and operate this pipeline, completed an open season with respect to a capacity expansion of the pipeline 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. This expansion was approved by the Federal Energy Regulatory Commission (the “FERC”) in September 2009.

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.

In January 2008, in conjunction with the signing of transportation commitments, MEP entered into an option agreement with a subsidiary of MarkWest Energy Partners, L.P. ("MarkWest"), providing it a one-time right to purchase a 10% ownership interest in MEP. In October 2009, MarkWest provided notice that it would not exercise the option.

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. Fayetteville Express Pipeline, LLC ("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 nine months ended September 30, 2009, we contributed $464.5 million to MEP and $70.0 million to FEP. In October 2009, we made an additional capital contribution of $200.0 million to MEP to reduce amounts outstanding under MEP's credit facility. We do not expect to make additional contributions to MEP during the remainder of 2009. With respect to FEP, we anticipate to make additional capital contributions of $140 million during the remainder of 2009 to fund FEP's capital expenditures. FEP is currently seeking financing, and if successful, we would not expect to make this additional capital contribution.

Summarized Financial Information

The following table presents aggregated selected income statement data for our unconsolidated affiliates, MEP and FEP (on a 100% basis):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenue	$ 38,157	$ -	$ 48,463	$ -
Operating income	18,271	-	21,047	-
Net income	17,602	-	19,313	1,058

As stated above, MEP was placed into service during 2009.

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 September 30, 2009 was $6.85 billion and $6.21 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 September 30, 2009 and December 31, 2008:

	Fair Value Measurements at September 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	$ 12,682	$ 12,682	$ -	$ 5,915	$ 5,915	$ -
Inventories (natural gas)	108,849	108,849	-	-	-	-
Commodity derivatives	19,990	13,149	6,841	111,513	106,090	5,423
Liabilities:						
Commodity derivatives	(22,664)	(22,340)	(324)	(43,336)	-	(43,336)
Interest rate swap derivatives	(17,954)	-	(17,954)	(51,642)	-	(51,642)
	$ 100,903	$ 112,340	$ (11,437)	$ 22,450	$ 112,005	$ (89,555)

In April 2009, we began designating as fair value hedges certain commodity derivatives that are utilized to manage price volatility associated with our natural gas inventory. 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.

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Current expense (benefit):				
Federal	$ (88)	$ (7,826)	$ (5,195)	$ (1,192)
State	3,231	5,072	10,126	13,856
Total	3,143	(2,754)	4,931	12,664
Deferred expense (benefit):				
Federal	(5,670)	(4,915)	3,472	(4,091)
State	(370)	519	191	181
Total	(6,040)	(4,396)	3,663	(3,910)
Total income tax expense (benefit)	$ (2,897)	$ (7,150)	$ 8,594	$ 8,754
Effective tax rate	(4.16%)	(3.34%)	1.59%	1.21%

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. As discussed in Note 2, the adoption of a new accounting principle required us to change our calculation of earnings per unit during periods where earnings exceeded distributions; 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 this change in accounting principle 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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 72,456	$ 221,048	$ 530,361	$ 715,057
General Partner's interest in net income	88,927	80,252	266,396	233,599
Limited Partners' interest in net income (loss)	(16,471)	140,796	263,965	481,458
Additional earnings allocated from General Partner	185	-	185	-
Distributions on employee unit awards, net of allocation to General Partner	(668)	-	(2,017)	-
Net income (loss) available to Limited Partners	$ (16,954)	$ 140,796	$ 262,133	$ 481,458
Weighted average Limited Partner units – basic	168,815,563	149,839,499	164,183,538	145,160,079
Basic net income (loss) per Limited Partner unit	$ (0.10)	$ 0.94	$ 1.60	$ 3.32
Weighted average Limited Partner units	168,815,563	149,839,499	164,183,538	145,160,079
Dilutive effect of Unit Grants	-	408,695	702,954	455,009
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	168,815,563	150,248,194	164,886,492	145,615,088
Diluted net income (loss) per Limited Partner unit	$ (0.10)	$ 0.94	$ 1.59	$ 3.31

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended September 30, 2009, are $249.5 million in total, which exceeds net income for the period by $177.0 million. Accordingly, the distributions to be paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended September 30, 2009, and as a result, a net loss was allocated to the Limited Partners for the period.

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 September 30, 2009, there was a balance of $483.3 million outstanding on the ETP Credit Facility, and taking into account letters of credit of approximately $65.1 million, $1.45 billion was available for future borrowings. The weighted average interest rate on the total amount outstanding at September 30, 2009, was 0.82%.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility. At September 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 September 30, 2009 was $74.0 million.

Other Long-Term Debt

In connection with our August 2009 acquisition of ETG (see Note 17), we assumed $17.0 million of long-term debt with interest rates averaging 7.48% and maturities through 2015.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at September 30, 2009.

13. PARTNERS' CAPITAL:

Common Units Issued

The change in Common Units during the nine months ended September 30, 2009 was 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	56,574
Balance, September 30, 2009	168,834,045

During 2009, we closed on the following public offerings of Common Units, which were registered under the Securities Act of 1933 pursuant to our Registration Statement on Form S-3ASR. The net proceeds were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint venture entities related to pipeline construction projects, and for general partnership purposes:

- 6,900,000 Common Units in January 2009 at $34.05 per Common Unit, resulting in net proceeds of approximately $225.9 million;
- 9,775,000 Common Units in April 2009 at $37.55 per Common Unit, resulting in net proceeds of approximately $352.4 million; and

- 6,900,000 Common Units in October 2009 at $41.27 per Common Unit, resulting in net proceeds of approximately $276.0 million.

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC (“UBS”). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate offering price of up to $300.0 million. Sales of the units will be made by means of ordinary brokers’ transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. As of September 30, 2009, we had not issued any Common Units pursuant to this agreement. We filed a Registration Statement on Form S-3 with the SEC that was declared effective under the Securities Act of 1933 on August 14, 2009, to register Common Units and debt securities with an aggregate offering price of $1.0 billion that may be offered for sale by us from time to time. Pursuant to that same Registration Statement, we also registered 12,000,000 of our outstanding Common Units that are currently held by Energy Transfer Equity, L.P. (“ETE”) and may be sold by ETE from time to time. In addition, we also filed a Registration Statement on Form S-4 with the SEC that was declared effective under the Securities Act of 1933 on October 2, 2009, to register 7,500,000 Common Units that may be issued from time to time in connection with one or more acquisitions.

Quarterly Distributions of Available Cash

Distributions paid during the nine months ended September 30, 2009, as well as the amount paid in the aggregate for ETP GP’s general partner interest in the Partnership and its IDRs, are summarized as follows:

Quarter Ended	Record Date	Payment Date	Amount per Unit	Aggregate General Partner Interest and IDRs
December 31, 2008	February 6, 2009	February 13, 2009	$ 0.89375	$ 83,859
March 31, 2009	May 8, 2009	May 15, 2009	0.89375	89,006
June 30, 2009	August 7, 2009	August 14, 2009	0.89375	89,025

On October 28, 2009, we declared a cash distribution for the three months ended September 30, 2009 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on November 16, 2009 to Unitholders of record at the close of business on November 9, 2009.

Total distributions declared (all from Available Cash from Operating Surplus, as defined in our Partnership Agreement) related to the nine months ended September 30, 2009 were as follows:

Limited Partners -	
Common Units	$ 458,836
Class E Units	9,363
General Partner Interest	14,587
Incentive Distribution Rights	255,809
	$ 738,595

Accumulated Other Comprehensive Income (Loss)

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

	September 30, 2009	December 31, 2008
Net gains (losses) on commodity related derivatives	$ (15,072)	$ 8,735
Net gains (losses) on interest rate derivatives	(55)	161
Unrealized gains (losses) on available-for-sale securities	775	(5,983)
Total AOCI, net of tax	$ (14,352)	$ 2,913

14. UNIT-BASED COMPENSATION PLANS:

Employee Grants

The following table shows the activity of the awards during the nine months ended September 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	(61,210)	40.16	-	-	(63,246)	40.28
Awards forfeited	(3,336)	43.96	(23,531)	36.51	-	-	(26,867)	37.44
Unvested awards as of September 30, 2009	145,480	43.96	1,156,539	35.59	8,976	43.48	1,310,995	36.57

(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 September 30, 2009, a total of 4,793,350 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 $4.9 million and $1.1 million for the three months ended September 30, 2009 and 2008, respectively. We recognized non-cash compensation expense related to employee grants under our unit-based compensation plans of $15.7 million and $12.5 million for the nine months ended September 30, 2009 and 2008, respectively. The total expected non-cash compensation expense to be recognized related to the unvested employee awards as of September 30, 2009 is:

Years Ending December 31:	
2009 (remainder)	$ 4,206
2010	10,038
2011	5,896
2012	3,089
2013	1,010

Director Grants

The following table shows the activity of the director grants during the nine months ended September 30, 2009:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2008	7,310	$ 40.72
Awards granted	4,340	33.28
Awards vested	(3,530)	43.68
Unvested awards as of September 30, 2009	8,120	35.46

We recognized non-cash compensation expense related to director grants under our unit-based compensation plans of $0.04 million and $0.05 million for the three months ended September 30, 2009 and 2008, respectively. We recognized non-cash compensation expense related to director grants under our unit-based compensation plans of $0.12 million and $0.12 million for the nine months ended September 30, 2009 and 2008, respectively. The total expected non-cash compensation expense to be recognized related to the unvested director grants as of September 30, 2009 is:

Years Ending December 31:	
2009 (remainder)	$ 37
2010	118
2011	41
2012	10

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 the entity that owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officer. As of September 30, 2009, rights related to 627,000 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 September 30, 2009 and 2008, we recognized non-cash compensation expense, net of forfeitures, of $1.5 million and $1.2 million, respectively. For the nine months ended September 30, 2009 and 2008, we recognized non-cash compensation expense, net of forfeitures, of $5.1 million and $1.7 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 our joint venture projects, 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 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 of September 30, 2009, MEP had $371.6 million 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 $185.8 million and $16.6 million, respectively, as of September 30, 2009.

In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by ETP or KMP. In October 2009, we made an additional capital contribution of $200 million to MEP, which MEP used to further reduce the outstanding borrowings under the MEP facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275 million.

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 $6.0 million and $6.3 million for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, rental expense totaled approximately $17.5 million and $21.7 million, respectively, for operating leases. In connection with our acquisition of ETG (see Note 17) in August 2009, we assumed operating leases with future minimum payments of approximately $5 million per year through July 2017.

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.

In February 2008, 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 August 26, 2009, we entered into a settlement agreement with the Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement settles all outstanding FERC claims against us and provides that we make a $5 million payment to the federal government and establish a $25 million fund for the purpose of settling related third party claims against us, including existing litigation claims as well as any new claims that may be asserted against this fund. An administrative law judge appointed by the FERC will determine the validity of any third party claim against this fund. Any party who receives money from this fund will be required to waive all claims against us related to this matter. Pursuant to the settlement agreement, the FERC will make no findings of fact or conclusions of law. In addition, the settlement agreement specifies that we do not admit or concede to any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims.

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. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 28, 2009, these decisions were appealed by the plaintiffs to the United States Court of Appeals for the Fifth Circuit.

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. On September 10, 2009, this decision was appealed by the plaintiff to the United States Court of Appeals for the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such expenses are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we increased our accrual for these matters to $30.0 million in the aggregate as of September 30, 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the accrual that is used to satisfy third party claims, which we expect to realize in future periods. Although this accrual covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obliged to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the new 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 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. Appellant sought appellate rehearing on the matter and the petition for rehearing was denied on May 4, 2009. A petition for writ of certiorari was filed by the Appellant on August 3, 2009, and the Supreme Court denied the petition for writ of certiorari on October 5, 2009. 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 of September 30, 2009 and December 31, 2008, accruals of approximately $9.5 million and $8.5 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of September 30, 2009 and December 31, 2008, accruals of approximately $30.0 million and $21.0 million, respectively, 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 as described above.

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 $8.7 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 nine months ended September 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 September 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 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 September 30, 2009 and December 31, 2008, an accrual on an undiscounted basis of $12.8 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 September 30, 2009 and 2008, $9.3 million and $6.8 million, respectively, of capital costs and $3.6 million and $2.0 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the nine months ended September 30, 2009 and 2008, $24.6 million and $12.3 million, respectively, of capital costs and $12.6 million and $12.7 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 our 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.
- 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 $11.7 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 or 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.

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 nine months ended September 30, 2009. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the nine months ended September 30, 2008.

Table of Contents

The following table details the outstanding commodity-related derivatives:

	Commodity	September 30, 2009 Notional Volume	September 30, 2009 Maturity	December 31, 2008 Notional Volume	December 31, 2008 Maturity
Mark to Market Derivatives					
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	78,932,500	2009-2011	15,720,000	2009-2011
Swing Swaps IFERC (MMBtu)	Natural Gas	(53,500,000)	2009-2010	(58,045,000)	2009
Fixed Swaps/Futures (MMBtu)	Natural Gas	(3,755,000)	2009-2011	(20,880,000)	2009-2010
Forwards/Swaps (Gallons)	Propane/Ethane	11,718,000	2009-2010	47,313,002	2009
Fair Value Hedging Derivatives					
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	(31,095,000)	2009-2010	-	N/A
Fixed Swaps/Futures (MMBtu)	Natural Gas	(31,967,500)	2009-2010	-	N/A
Hedged Item - Inventory	Natural Gas	31,967,500	2009-2010	-	N/A
Cash Flow Hedging Derivatives					
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	(16,830,000)	2009-2010	(9,085,000)	2009
Fixed Swaps/Futures (MMBtu)	Natural Gas	(27,625,000)	2009-2010	(9,085,000)	2009
Forward/Swaps (Gallons)	Propane/Ethane	28,518,000	2009-2010	-	N/A

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. As of September 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.

Derivative Summary

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

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	September 30, 2009	December 31, 2008	September 30, 2009	December 31, 2008
Derivatives designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 331	$ 10,665	$ (32,831)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	4,345	918	(175)	(119)
Total derivatives designated as hedging instruments		$ 4,676	$ 11,583	$ (33,006)	$ (1,623)
Derivatives not designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	41,613	432,614	(18,305)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	2,607	17,244	(261)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	-	-	(17,954)	(51,643)
Total derivatives not designated as hedging instruments		$ 44,220	$ 449,858	$ (36,520)	$ (443,282)
Total derivatives		$ 48,896	$ 461,441	$ (69,526)	$ (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.

Table of Contents

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 $99.3 million and $78.2 million as of September 30, 2009 and December 31, 2008, respectively, reflected as deposits paid to vendors in our condensed consolidated balance sheets.

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)		Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives	
		Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
		2009	2008	2009	2008	2009	2008
Derivatives in cash flow hedging relationships:							
Commodity Derivatives	Cost of Products Sold	$ (15,146)	$ 7,042	$ (847)	$ 483	$ (95)	$ (11)
Interest Rate Swap Derivatives	Interest Expense	-	-	71	72	-	-
Total		$ (15,146)	$ 7,042	$ (776)	$ 555	$ (95)	$ (11)
		Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
		2009	2008	2009	2008	2009	2008
Derivatives in cash flow hedging relationships:							
Commodity Derivatives	Cost of Products Sold	$ (15,282)	$ (530)	$ 8,702	$ 21,666	$ (95)	$ (8,347)
Interest Rate Swap Derivatives	Interest Expense	-	-	215	573	-	-
Total		$ (15,282)	$ (530)	$ 8,917	$ 22,239	$ (95)	$ (8,347)

	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 September 30,		Nine Months Ended September 30,	
		2009	2008	2009	2008
Derivatives in fair value hedging relationships:					
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ (20,909)	$ -	$ (8,411)	$ -
Total		$ (20,909)	$ -	$ (8,411)	$ -

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2009	2008	2009	2008
Derivatives not designated as hedging instruments:					
Commodity Derivatives	Cost of Products Sold	$ 30,346	$ 83,337	$ 87,349	$ (241)
Trading Commodity Derivatives	Revenue	-	(36,729)	-	(28,283)
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	(18,241)	394	32,327	149
Total		$ 12,105	$ 47,002	$ 119,676	$ (28,375)

We recognized $13.5 million and $34.4 million of unrealized gains on commodity derivatives not in fair value hedging relationships (including amounts related to the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, we recognized unrealized losses on commodity derivatives not in fair value hedging relationships of $32.7 million and $5.8 million, respectively. For the three and nine months ended September 30, 2009, we recognized unrealized losses of $16.4 million and $3.9 million, respectively, on commodity derivatives and related hedged inventory in fair value hedging relationships. There were no unrealized gains or losses on commodity derivatives and related hedged inventory in fair value hedging relationships in the prior year as we did not begin applying fair hedge accounting on our storage inventory until April 2009.

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.

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 our financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our condensed consolidated balance 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 September 30,				Nine Months Ended September 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)	3,570	$ 2,538	1,050	$ 1,529	20,370	$ 14,046	13,230	$ 19,769
	Derivative Activity	-	277	-	66	-	277	-	2,442
Purchases	Propane (Gallons)	47,124	$ 43,579	51,116	$ 89,391	206,344	$ 181,853	219,711	$ 367,774
	Derivative Activity		443	-	757	-	38,392	-	757
Natural Gas Operations:									
Sales	NGLs (Gallons)	127,814	$ 108,218	23,362	$ 37,191	368,652	$ 259,417	39,339	$ 62,104
	Natural Gas (MMBtu)	3,378	11,116	1,854	17,345	7,476	27,165	4,886	44,023
	Fees	-	(1,062)	-	1,493	-	(3,236)	-	4,651
Purchases	Natural Gas Imbalances (MMBtu)	366	$ 1,404	(1,382)	$ (4,299)	617	$ 1,903	599	$ (1,379)
	Natural Gas (MMBtu)	3,493	11,745	5,609	41,726	7,089	27,359	10,938	93,699
	Fees	-	(191)	-	13,148	-	42	-	13,660

Accounts receivable from and accounts payable to related companies as of September 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 September 30, 2009 and December 31, 2008, Titan had forward mark-to-market derivatives for approximately 11.7 million and 45.2 million gallons of propane at a fair value asset of $2.4 million and a fair value liability of $40.1 million, respectively, with Enterprise. In addition, as of September 30, 2009, Titan had forward derivatives accounted for as cash flow hedges of 28.5 million gallons of propane at a fair value asset of $4.3 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:

	September 30, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 28,366	$ 11,558
Accounts payable	265	567
Imbalance payable	(2,391)	(547)
Propane Operations:		
Accounts receivable	$ 325	$ 111
Accounts payable	5,962	33,308

Accounts receivable from related companies other than Enterprise consist of the following:

	September 30, 2009	December 31, 2008
ETP GP	$ 217	$ 122
ETE	4,948	2,632
MEP	725	2,805
FEP	113	-
McReynolds Energy	-	202
Energy Transfer Technologies, Ltd.	-	16
Others	1,278	449
Total accounts receivable from related companies other than Enterprise	$ 7,281	$ 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 $0.9 million ($0.4 million in salary and $0.5 million in accrued bonuses) for the nine months ended September 30, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

Effective August 17, 2009, we acquired 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of our General Partner's general partner and the other of which is controlled by a member of ETP's management. In exchange, the former members acquired the right to receive (in cash or Common Units), future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG will receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.1 million and recorded goodwill of $1.3 million.

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.

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

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 Companies 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.

The amounts allocated for the periods presented are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Costs allocated from ETP to Operating Partnerships:				
Midstream and intrastate transportation and storage operations	$ 4,785	$ 4,162	$ 15,363	$ 12,747
Interstate operations	1,495	1,200	4,793	3,706
Retail propane and other retail propane related operations	3,689	2,642	11,795	8,167
Total	$ 9,969	$ 8,004	$ 31,951	$ 24,620
Costs allocated from Operating Partnerships to ETP:				
Midstream and intrastate transportation and storage operations	$ 2,838	$ 3,634	$ 11,014	$ 7,567
Retail propane and other retail propane related operations	-	776	412	2,129
Total	$ 2,838	$ 4,410	$ 11,426	$ 9,696

Table of Contents

The following tables present the financial information by segment for the following periods:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 364,087	$ 875,186	$ 1,192,564	$ 2,854,708
Intersegment revenues	102,626	634,369	396,734	2,007,933
	466,713	1,509,555	1,589,298	4,862,641
Interstate transportation - revenues from external customers	71,415	62,023	203,349	176,663
Midstream:				
Revenues from external customers	507,721	1,001,378	1,607,497	3,290,699
Intersegment revenues	65,345	433,779	142,969	1,264,641
	573,066	1,435,157	1,750,466	4,555,340
Retail propane and other retail propane related - revenues from external customers	184,287	263,566	902,471	1,162,941
All other:				
Revenues from external customers	2,086	4,063	5,632	14,051
Intersegment revenues	372	-	372	-
	2,458	4,063	6,004	14,051
Eliminations	(168,343)	(1,068,149)	(540,075)	(3,272,574)
Total revenues	$ 1,129,596	$ 2,206,215	$ 3,911,513	$ 7,499,062
Cost of products sold:				
Intrastate transportation and storage	$ 278,868	$ 1,150,799	$ 895,433	$ 3,965,931
Midstream	480,746	1,352,658	1,510,030	4,271,788
Retail propane and other retail propane related	85,028	195,403	393,019	761,415
All other	1,849	2,743	4,873	10,684
Eliminations	(168,343)	(1,068,149)	(540,075)	(3,272,574)
Total cost of products sold	$ 678,148	$ 1,633,454	$ 2,263,280	$ 5,737,244
Depreciation and amortization:				
Intrastate transportation and storage	$ 27,188	$ 23,820	$ 78,080	$ 60,293
Interstate transportation	12,521	9,637	36,017	28,204
Midstream	18,091	16,669	51,792	44,004
Retail propane and other retail propane related	23,031	20,255	63,477	58,828
All other	853	127	1,095	428
Total depreciation and amortization	$ 81,684	$ 70,508	$ 230,461	$ 191,757
Operating income (loss):				
Intrastate transportation and storage	$ 109,781	$ 229,921	$ 410,425	$ 554,140
Interstate transportation	41,610	33,698	101,755	91,414
Midstream	43,414	39,862	96,603	157,517
Retail propane and other retail propane related	(16,550)	(39,728)	152,079	61,705
All other	(3,021)	(186)	(4,803)	(528)
Selling, general and administrative expenses not allocated to segments	2,113	(3,059)	1,361	(4,425)
Total operating income	$ 177,347	$ 260,508	$ 757,420	$ 859,823
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (101,503)	$ (67,792)	$ (284,228)	$ (191,757)
Equity in earnings (losses) of affiliates	9,581	(654)	11,751	(749)
Gains (losses) on disposal of assets	(1,088)	2,520	(1,333)	1,584
Gains (losses) on non-hedged interest rate derivatives	(18,241)	394	32,327	149
Allowance for equity funds used during construction	30	19,727	18,618	45,275
Other, net	3,433	(805)	4,400	9,486
Income tax benefit (expense)	2,897	7,150	(8,594)	(8,754)
	(104,891)	(39,460)	(227,059)	(144,766)
Net income	$ 72,456	$ 221,048	$ 530,361	$ 715,057

	As of September 30, 2009	As of December 31, 2008
Total assets:		
Intrastate transportation and storage	$ 4,697,489	$ 4,642,430
Interstate transportation	3,158,799	2,487,078
Midstream	1,559,551	1,537,972
Retail propane and other retail propane related	1,687,870	1,810,953
All other	151,011	149,056
Total	$ 11,254,720	$ 10,627,489

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 362,816	$ 728,028
Interstate transportation	127,927	621,807
Midstream	76,408	204,610
Retail propane and other retail propane related	45,904	97,602
All other	29,404	1,800
Total	$ 642,459	$ 1,653,847

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 the year ended December 31, 2008 filed with the 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 Companies. The Partnership and the Operating Companies 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 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, of assets totaling $3.9 billion in our natural gas operations and $0.85 billion 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 September 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 $5.0 billion, of which more than $4.3 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.

In January 2008, in conjunction with the signing of transportation commitments, MEP entered into an option agreement with a subsidiary of MarkWest Energy Partners, L.P. ("MarkWest"), providing it a one-time right to purchase a 10% ownership interest in MEP. In October 2009, MarkWest provided notice that it would not exercise the option.

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. These measures include, but are 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 manage operating and administrative costs. During the nine months ended September 30, 2009, we received approximately $578.3 million in net proceeds from our January and April Common Unit offerings and $993.6 million in net proceeds from an offering of $1.0 billion of aggregate principal amount of senior notes in April. As of September 30, 2009, in addition to approximately $50.1 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.45 billion. In addition, we received approximately $276.0 million in net proceeds from our October Common Unit offering. 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 $2.4 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 the 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 and have remained at low levels due to the continued effects of the economic recession and higher than normal storage levels. 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. These 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 the shutting 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 nine months of 2009, natural gas spot prices have ranged from $1.925 per MMbtu to $5.25 per MMbtu, and the closing price on the NYMEX on November 6, 2009 for natural gas to be delivered in December 2009 was $4.595 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.

Table of Contents

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 September 30,			Nine Months Ended September 30,		
	2009	2008	Change	2009	2008	Change
Revenues	$ 1,129,596	$ 2,206,215	$ (1,076,619)	$ 3,911,513	$ 7,499,062	$ (3,587,549)
Cost of products sold	678,148	1,633,454	(955,306)	2,263,280	5,737,244	(3,473,964)
Gross margin	451,448	572,761	(121,313)	1,648,233	1,761,818	(113,585)
Operating expenses	158,883	197,493	(38,610)	517,337	573,606	(56,269)
Depreciation and amortization	81,684	70,508	11,176	230,461	191,757	38,704
Selling, general and administrative	33,534	44,252	(10,718)	143,015	136,632	6,383
Operating income	177,347	260,508	(83,161)	757,420	859,823	(102,403)
Interest expense, net of interest capitalized	(101,503)	(67,792)	(33,711)	(284,228)	(191,757)	(92,471)
Equity in earnings (losses) of affiliates	9,581	(654)	10,235	11,751	(749)	12,500
Gains (losses) on disposal of assets	(1,088)	2,520	(3,608)	(1,333)	1,584	(2,917)
Gains (losses) on non-hedged interest rate derivatives	(18,241)	394	(18,635)	32,327	149	32,178
Allowance for equity funds used during construction	30	19,727	(19,697)	18,618	45,275	(26,657)
Other, net	3,433	(805)	4,238	4,400	9,486	(5,086)
Income tax benefit (expense)	2,897	7,150	(4,253)	(8,594)	(8,754)	160
Net income	$ 72,456	$ 221,048	$ (148,592)	$ 530,361	$ 715,057	$ (184,696)

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, including capital contributions to our joint ventures. Interest expense is presented net of capitalized interest and allowance for debt funds used during construction, which totaled $5.7 million and $7.9 million for the three months ended September 30, 2009 and 2008, respectively, and $15.5 million and $24.3 million for the nine months ended September 30, 2009 and 2008, respectively.

Equity in Earnings (Losses) of Affiliates. The increase in equity in earnings of affiliates for both the three and nine month periods was primarily attributable to earnings of MEP during the three months ended September 30, 2009, for which we recorded $7.0 million and $1.8 million, respectively.

Gains (Losses) on Non-Hedged Interest Rate Derivatives. Changes between the periods are a result of changes in the relevant floating index rates.

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. AFUDC on equity amounts recorded in property, plant and equipment were $0.02 million and $12.1 million for the three months ended September 30, 2009 and 2008, respectively, and $11.4 million and $27.7 million for the nine months ended September 30, 2009 and 2008, respectively.

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

Income Tax Expense. As a partnership, we are generally not subject to income taxes. However, certain wholly-owned subsidiaries are corporations that are subject to income taxes. For the three months ended September 30, 2009, the tax benefit resulted from the settlement of the FERC's market manipulation claims in August 2009. For the three months ended September 30, 2008, the tax benefit resulted from trading losses incurred by our corporate subsidiaries in July 2008.

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 the year ended December 31, 2008 filed with the SEC on March 2, 2009.

Operating income by segment is as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Change	2009	2008	Change
Intrastate transportation and storage	$ 109,781	$ 229,921	$ (120,140)	$ 410,425	$ 554,140	$ (143,715)
Interstate transportation	41,610	33,698	7,912	101,755	91,414	10,341
Midstream	43,414	39,862	3,552	96,603	157,517	(60,914)
Retail propane and other retail propane related	(16,550)	(39,728)	23,178	152,079	61,705	90,374
Other	(3,021)	(186)	(2,835)	(4,803)	(528)	(4,275)
Unallocated selling, general and administrative expenses	2,113	(3,059)	5,172	1,361	(4,425)	5,786
Operating income	$ 177,347	$ 260,508	$ (83,161)	$ 757,420	$ 859,823	$ (102,403)

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses are allocated monthly to the Operating Companies 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 September 30,			Nine Months Ended September 30,		
	2009	2008	Change	2009	2008	Change
Natural gas MMBtu/d - transported	11,111,011	11,613,933	(502,922)	12,769,022	10,515,132	2,253,890
Natural gas MMBtu/d - sold	886,463	1,409,348	(522,885)	879,861	1,556,524	(676,663)
Revenues	$ 466,713	$ 1,509,555	$(1,042,842)	$ 1,589,298	$ 4,862,641	$(3,273,343)
Cost of products sold	278,868	1,150,799	(871,931)	895,433	3,965,931	(3,070,498)
Gross margin	187,845	358,756	(170,911)	693,865	896,710	(202,845)
Operating expenses	45,053	86,332	(41,279)	155,461	227,026	(71,565)
Depreciation and amortization	27,188	23,820	3,368	78,080	60,293	17,787
Selling, general and administrative	5,823	18,683	(12,860)	49,899	55,251	(5,352)
Segment operating income	$ 109,781	$ 229,921	$ (120,140)	$ 410,425	$ 554,140	$ (143,715)

Gross Margin.

Three Months

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

- 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 decrease in natural gas prices, fuel retention margin decreased approximately $62.1 million compared to the prior period despite increases in volumes transported. Natural gas prices for retained fuel decreased from an average of $8.98/MMBtu during the three months ended September 30, 2008 to $3.16/MMBtu during the three months ended September 30, 2009.
- We experienced a net decrease in storage margin of $90.1 million between the periods due primarily to unfavorable changes in derivative activity. During the 2008 period, we accounted for our storage-related derivative instruments using mark to market accounting, with changes in the fair value of these derivatives being recorded directly in earnings. Due to the sharp

decreases in natural gas forward prices during the three months ended September 30, 2008, we recognized unrealized gains of $47.8 million from mark to market adjustments and realized gains of $23.0 million from the settlement of these derivative contracts. During the 2009 period, we accounted for certain storage-related transactions using fair value hedge accounting. Due to changes in the spot price used to value natural gas inventory held in storage and changes in the forward natural gas prices used to value the financial derivatives, we recognized $10.0 million in realized gains from the settlement of the derivative contracts and $23.1 million in unrealized losses from fair value adjustments during the three months ended September 30, 2009. In addition, we recorded a non-cash lower of cost or market write-down of our natural gas inventory of $9.4 million related to the timing of our designation of fair value hedges during the three months ended September 30, 2009. Fee-based storage and other factors also increased our margin by $3.3 million as compared to the prior period.

- Transportation fees decreased approximately $9.6 million primarily as a result of decreases in volumes transported due to weaker price differentials between major market hubs where our assets are located.
- In addition to the above factors, we experienced a reduction in margin of $9.1 million as compared to the prior period principally due to the decrease in natural gas sold as a result of lower natural gas prices, lower west to east price differentials, and lower demand from industrial end users and local distribution companies.

Nine Months

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

- 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 margins increased approximately $32.0 million compared to the prior period. However, natural gas prices for retained fuel decreased from an average of $8.99/MMBtu during the nine months ended September 30, 2008 to $3.25/MMBtu during the nine months ended September 30, 2009 resulting in a decrease to the retention margin of $179.0 million.
- We experienced a net decrease in storage margin of $87.5 million primarily due to a decrease in realized margin of $87.9 million as a result of a 24.7 Bcf decrease in natural gas sold between the periods from our Bammel Storage Facility. In addition, we experienced fluctuations related to our storage-related derivative activities that resulted in a net increase of $0.4 million. During the 2008 period and the first three months of 2009, we accounted for certain of our storage-related derivative instruments using mark to market accounting with changes in the value of these financial derivative instruments being recorded directly in earnings. During the nine months ended September 30, 2008, we recognized unrealized gains of $23.1 million from mark to market adjustments and realized losses of $5.7 million from the settlement of derivative contracts. During the three months ended March 31, 2009, we recognized $66.3 million in net gains from mark to market adjustments and the settlement of storage-related derivative contracts primarily due to expected natural gas withdrawals that were ultimately deferred. Beginning in April 2009, we elected fair value hedge accounting for certain storage-related transactions and recognized $3.5 million in realized gains from the settlement of derivative contracts and $2.1 million in unrealized gains from inventory fair value adjustments related to changes in the spot prices for natural gas and changes in value of the financial derivatives associated with storage during the nine months ended September 30, 2009. In addition, during the nine months ended September 30, 2009, we recognized $54.0 million in unrealized losses as a result of a non-cash lower of cost or market write-down of our natural gas inventory.
- Transportation fees increased approximately $84.8 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.
- In addition to the above factors, we experienced a reduction in margin of $53.1 million as compared to the prior period principally due to the decrease in natural gas sold as a result of lower natural gas prices, lower west to east price differentials, and lower demand from industrial end users and local distribution companies.

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 $35.9 million, which was principally caused by lower natural gas prices between periods despite increases in volumes transported, and a decrease in electricity costs of approximately $4.8 million.

Nine Months

Intrastate transportation and storage operating expenses decreased between the nine month periods primarily due to a decrease in consumption expense of $82.6 million, which was principally caused by lower natural gas prices between periods despite increases in volumes transported, and a decrease in electricity costs of approximately $6.6 million. Offsetting the decrease were increases in ad valorem taxes of $12.9 million, resulting from increased property values, and pipeline maintenance expenses of approximately $5.0 million.

Depreciation and Amortization.

Three and Nine Months

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

Selling, General and Administrative.

Three Months

Intrastate transportation and storage selling, general and administrative expenses decreased between the three month periods primarily due to a decrease in employee-related expenses (including allocated overhead expenses) of approximately $14.1 million offset by an increase of approximately $1.3 million in professional fees during the period.

Nine Months

Intrastate transportation and storage selling, general and administrative expenses decreased between the nine month periods primarily due to decreased employee-related costs (including allocated overhead expenses) of approximately $8.9 million offset by an increase in professional fees of approximately $3.7 million during the period.

Interstate Transportation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Change	2009	2008	Change
Natural gas MMBtu/d - transported	1,688,388	1,862,781	(174,393)	1,706,199	1,750,592	(44,393)
Natural gas MMBtu/d - sold	19,060	14,784	4,276	19,481	13,094	6,387
Revenues	$ 71,415	$ 62,023	$ 9,392	$ 203,349	$ 176,663	$ 26,686
Operating expenses	13,718	13,278	440	46,427	39,128	7,299
Depreciation and amortization	12,521	9,637	2,884	36,017	28,204	7,813
Selling, general and administrative	3,566	5,410	(1,844)	19,150	17,917	1,233
Segment operating income	$ 41,610	$ 33,698	$ 7,912	$ 101,755	$ 91,414	$ 10,341

Revenues.

Three Months

Interstate revenues increased between the three month periods by approximately $9.4 million primarily due to the increased transportation revenues of $14.0 million as a result of the completion of the Phoenix pipeline expansion in February 2009, partially offset by a $4.6 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 pricing differentials between the San Juan and Permian Basins during the three months ended September 30, 2009.

Nine Months

Interstate revenues increased between the nine month periods by approximately $26.7 million due to a $38.5 million increase related to increased transported natural gas volumes primarily as a result of the completion of the Phoenix pipeline expansion in February 2009, partially offset by a $11.8 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 pricing differentials between the San Juan and Permian Basins during the period.

Operating Expenses.

Three Months

Interstate operating expenses increased between the three month periods primarily due to an increase in ad valorem taxes resulting from increased property values due to the Phoenix pipeline expansion noted above.

Nine Months

Interstate operating expenses increased between the nine month periods primarily due to an increase in ad valorem taxes of approximately $4.0 million resulting from increased property values and a net increase in other operating expenses of $3.3 million primarily in connection with the Phoenix pipeline expansion 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 Phoenix pipeline expansion.

Nine Months

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

Selling, General and Administrative.

Three Months

Interstate selling, general and administrative expenses decreased between the three month periods primarily due to a decrease in employee-related costs

Nine Months

Interstate selling, general and administrative expenses increased between the nine month periods primarily due to an increase in allocated overhead expenses and professional fees.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Change	2009	2008	Change
Natural gas MMBtu/d - sold	1,021,963	1,344,033	(322,070)	1,009,547	1,361,295	(351,748)
NGLs Bbls/d - sold	39,486	24,019	15,467	40,345	27,618	12,727
Revenues	$ 573,066	$ 1,435,157	$ (862,091)	$ 1,750,466	$ 4,555,340	$(2,804,874)
Cost of products sold	480,746	1,352,658	(871,912)	1,510,030	4,271,788	(2,761,758)
Gross margin	92,320	82,499	9,821	240,436	283,552	(43,116)
Operating expenses	16,054	16,661	(607)	50,858	50,792	66
Depreciation and amortization	18,091	16,669	1,422	51,792	44,004	7,788
Selling, general and administrative	14,761	9,307	5,454	41,183	31,239	9,944
Segment operating income	$ 43,414	$ 39,862	$ 3,552	$ 96,603	$ 157,517	$ (60,914)

Gross Margin.

Three Months

Midstream gross margin increased during the three month period primarily due to a favorable change in marketing activity between the three month periods of approximately $36.7 million. This increase was due to the cessation of our trading activities in the third quarter of 2008 offset by an unfavorable change of $8.1 million in other marketing activities resulting from unfavorable pricing differentials between asset locations during the period. In addition, we experienced a decrease in our processing margin of approximately $17.6 million principally due to less favorable processing conditions in the 2009 period. The decrease in natural gas volumes sold was due to less end user demand and the increase in NGL volumes sold was principally due to increased capacity to deliver NGL volumes at our Godley plant starting in January 2009.

Nine Months

Midstream gross margin decreased between the nine month periods primarily due to a decrease in processing margin of $75.3 million partially offset by an increase in fee-based revenue of $8.0 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, which allowed us to charge additional processing fees. The decrease in processing margins was primarily due to less favorable processing conditions during the 2009 period. The decrease in the volumes of natural gas sold was primarily due to less favorable market conditions as compared to the prior period and the increase in NGL volumes sold was due to increased capacity to deliver NGL volumes at our Godley plant starting in

January 2009. We also experienced a favorable change in marketing activity between the periods of approximately $28.3 million due to the cessation of trading activity noted above offset by an unfavorable change of $4.1 million in other marketing activities resulting from unfavorable market conditions during the period.

Operating Expenses.

Three Months

Midstream operating expenses decreased between the three month periods primarily due to a net decrease in other operating expenses of $1.5 million partially offset by an increase in ad valorem taxes of approximately $0.9 million.

Nine Months

Midstream operating expenses increased between the nine month periods primarily due to increases in ad valorem taxes of $2.7 million and electricity expenses of $1.0 million. These increases were offset by a decrease in plant operating expenses of $1.2 million and a net decrease of approximately $2.5 million in other operating expenses.

Depreciation and Amortization.

Three and Nine Months

Midstream depreciation and amortization expense increased between the three and nine 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 approximately $1.7 million and the increase in our accrual of $10.0 million during the period related to the FERC matter. The increase was partially offset by a decrease in employee-related costs (including allocated overhead expenses) of $4.5 million and a net decrease of approximately $1.7 million in other expenses.

Nine Months

Midstream selling, general and administrative expenses increased between the nine month periods primarily due to an increase in professional fees of $8.4 million and the increase in our accrual of $10.0 million related to the FERC matter during the third quarter of 2009. This increase was partially offset by a net decrease in employee related costs (including allocated overhead expenses) of approximately $8.5 million.

Retail Propane and Other Retail Propane Related

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Change	2009	2008	Change
Retail propane gallons (in thousands)	87,569	90,386	(2,817)	398,202	422,109	(23,907)
Retail propane revenues	$ 162,224	$ 238,830	$ (76,606)	$ 829,901	$ 1,086,417	$ (256,516)
Other retail propane related revenues	22,063	24,736	(2,673)	72,570	76,524	(3,954)
Retail propane cost of products sold	80,232	187,799	(107,567)	378,524	744,316	(365,792)
Other retail propane related cost of products sold	4,796	7,604	(2,808)	14,495	17,099	(2,604)
Gross margin	99,259	68,163	31,096	509,452	401,526	107,926
Operating expenses	81,298	79,843	1,455	259,768	253,193	6,575
Depreciation and amortization	23,031	20,255	2,776	63,477	58,828	4,649
Selling, general and administrative	11,480	7,793	3,687	34,128	27,800	6,328
Segment operating income (loss)	$ (16,550)	$ (39,728)	$ 23,178	$ 152,079	$ 61,705	$ 90,374

Volumes.

Retail propane volumes decreased primarily due to the continued effects of customer conservation, the impact of the economic recession and, to a lesser extent, the decline in new home construction. These decreases were partially offset by the volume increases from acquisitions that are not included in the comparative periods. We use information gathered on temperatures based on heating degree days to also analyze our volume sales. Weather conditions can have a significant impact to the demand for propane volumes sales during the heating season, but temperatures during the nine months ended September 30, 2009 were only slightly colder than normal and were slightly warmer than the same period in 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 between the periods and due to changes in fair value of our non-hedged financial instruments. Our average cost per gallon of propane was approximately 50.0% lower during the three months ended September 30, 2009 as compared to the three months ended September 30, 2008. Unrealized gains recorded during the three months ended September 30, 2009 that related to the mark-to-market contracts were $1.5 million compared to $21.7 million of unrealized losses for the three months ended September 30, 2008, which affected the comparability in the gross margins between the three month periods.

Nine Months

Total gross margin increased between the nine 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 45.0% lower during the nine months ended September 30, 2009 as compared to the nine months ended September 30, 2008. 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 nine months ended September 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 $42.6 million of losses that had previously been recognized in 2008.

Operating Expenses.

Three Months

The primary factors that affected our operating expenses for the three months ended September 30, 2009 were an increase in our benefit costs provided to employees of $2.1 million and an increase of $2.6 million in our business insurance reserves and claims. These increases are due to an increase in insurance claims during the three months ended September 30, 2009 coupled with rising insurance costs. Our operational employee incentive program costs were $1.1 million higher for the three months ended September 30, 2009 as compared to the three months ended September 30, 2008 due to favorable results achieved in comparison to the prior quarter. Propane operating expenses also increased slightly due to the additional operating expenses from acquisitions made since September 30, 2008; however, these increases were offset by cost control initiatives from our operations and by a decrease of $2.8 million in the vehicle fuel used for delivery to customers due to the significant decline in fuel prices between the periods.

Nine Months

The primary factors that affected our operating expenses for the nine months ended September 30, 2009 were an increase in our operational employee incentive program of $9.2 million due to more favorable results achieved during the nine months ended September 30, 2009 as compared to the prior period and an increase in employee wages and benefits of $6.4 million due to an increase related to additional employees from acquisitions completed after September 30, 2008, fiscal year merit increases given October 2008, and an increase in medical costs. Our business insurance reserves and claims also increased $2.9 million for the nine months ended September 20, 2009 as compared to the prior period. These increases are primarily due to increases in insurance claims coupled with rising insurance costs. Other propane operating expenses also increased slightly due to the additional operating expenses from acquisitions made since September 30, 2008; however, these increases were largely offset by cost control initiatives from our operations and by a decrease of $9.1 million in the vehicle fuel used for delivery to customers due to the significant decline in fuel prices between the periods.

Depreciation and Amortization.

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

Selling, General and Administrative.

The increase in selling, general and administrative expenses between comparable periods was primarily due to increased administrative expense allocations of $1.8 million and $5.3 million for the three and nine month periods, respectively, offset by a 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 $30 million and $40 million during the last three months of 2009 and between $60 million and $80 million in 2010;
- 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 $80 million and $100 million during the last three months of 2009 and between $880 million and $900 million in 2010;
- capital contributions to MEP and FEP as follows:
    - With respect to MEP, capital expenditures have been funded under a revolving credit facility at MEP and through capital contributions from us and KMP. In September 2009, MEP issued $800 million of senior unsecured notes and used the proceeds to reduce amounts outstanding under its credit facility. We made a contribution of $200 million to MEP during October 2009 and do not expect any additional capital contributions during the remainder of 2009. The October 2009 contribution was used to further reduce amounts outstanding under MEP's credit facility. Subsequent to these repayments, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275 million. Availability on MEP's credit facility will be used to fund capital expenditures associated with MEP's expansion projects that are expected to be completed by December 2010. For 2010, we expect our capital contributions to MEP to be between $80 million and $90 million.
    - With respect to FEP, it is in the process of finalizing the terms of a senior unsecured revolving credit facility of up to $1.1 billion, which will be severally guaranteed by us and KMP. If the credit facility closes in November 2009 as currently anticipated, we would not expect making additional capital contributions to FEP and would be reimbursed for our prior capital contributions, which totaled $70.0 million through September 30, 2009. If the credit facility does not close, we expect that we would need to make additional capital contributions of $140 million during the remainder of 2009 and between $300 million and $320 million in 2010 to fund FEP's capital expenditures.
- growth capital expenditures for our retail propane segment of between $10 million and $20 million during the last three months of 2009 and between $30 million and $40 million in 2010;
- maintenance capital expenditures of between $35 million and $45 million during the last three months of 2009 and between $120 million and $130 million in 2010; 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 manage operating and administrative costs. During the nine months ended September 30, 2009, we received approximately $578.3 million in net proceeds from our January and April Common Unit offerings and $993.6 million in net proceeds from an offering of $1.0 billion of aggregate principal amount of senior notes in April. As of September 30, 2009, in addition to approximately $50.1 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.45 billion. In addition, we received approximately $276.0 million in net proceeds from our October Common Unit offering. 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. 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 factors include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions and other factors.

Operating Activities – Nine months ended September 30, 2009 compared to nine months ended September 30, 2008. Cash provided by operating activities during 2009 was $796.0 million as compared to $994.9 million for 2008. Net income was $530.4 million and $715.1 million for 2009 and 2008, respectively. The difference between net income and the net cash provided by operating activities consisted of non-cash items totaling $241.4 million and $170.1 million and changes in operating assets and liabilities of $24.3 million and $109.8 million for 2009 and 2008, respectively.

The non-cash activity in 2009 and 2008 consisted primarily of depreciation and amortization of $230.5 million and $191.8 million, respectively. In addition, non-cash compensation expense was $21.9 million and $15.3 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 $45.3 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 – Nine months ended September 30, 2009 compared to nine months ended September 30, 2008. Cash used in investing activities during 2009 was $1.23 billion as compared to $1.44 billion for 2008. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2009 were $703.5 million, including changes in accruals of $98.3 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2008 of $1.51 billion, including changes in accruals of $119.2 million. In addition, in 2009 we made advances to our joint ventures of $534.5 million. In 2008, we paid $62.0 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 $394.5 million for our midstream and intrastate transportation and storage segments, $107.7 million for our interstate transportation segment, and $31.3 million for our retail propane segment and all other. We also incurred $71.8 million of maintenance capital expenditures, of which $45.4 million related to our midstream and intrastate transportation and storage segments, $8.9 million related to our interstate segment and $17.4 million related to our retail propane segment.

Growth capital expenditures for 2008, before changes in accruals, were $935.5 million for our midstream and intrastate transportation and storage segments, $581.0 million for our interstate transportation segment, and $34.5 million for our retail propane segment and all other. We also incurred $75.9 million in maintenance expenditures, of which $43.0 million related to our midstream and intrastate transportation and storage segments, $13.5 million related to our interstate transportation segment and $19.4 million related to our retail propane segment.

Financing Activities – Nine months ended September 30, 2009 compared to nine months ended September 30, 2008. Cash provided by financing activities during 2009 was $387.9 million as compared to $914.4 million for 2008. In 2009, we received $578.9 million in net proceeds from Common Unit offerings as compared to $373.1 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 $519.0 million as compared to a net increase in our debt level of $1.22 billion for 2008. In addition, we paid distributions of $705.7 million to our partners in 2009 as compared to $663.2 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

During 2009, we closed on the following public offerings of Common Units, which were registered under the Securities Act pursuant to our Registration Statement on Form S-3ASR. The net proceeds were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint venture entities related to pipeline construction projects, and for general partnership purposes:

- 6,900,000 Common Units in January 2009 at $34.05 per Common Unit, resulting in net proceeds of approximately $225.9 million;
- 9,775,000 Common Units in April 2009 at $37.55 per Common Unit, resulting in net proceeds of approximately $352.4 million; and
- 6,900,000 Common Units in October 2009 at $41.27 per Common Unit, resulting in net proceeds of approximately $276.0 million.

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.

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS. Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate offering price of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. As of September 30, 2009, we had not issued any Common Units pursuant to this agreement.

We filed a Registration Statement on Form S-3 with the SEC that was declared effective under the Securities Act of 1933 on August 14, 2009, to register Common Units and debt securities with an aggregate offering price of $1.0 billion that may be offered for sale by us from time to time. Pursuant to that same Registration Statement, we also registered 12,000,000 of our outstanding Common Units that are currently held by ETE and may be sold by ETE from time to time. In addition, we also filed a Registration Statement on Form S-4 with the SEC that was declared effective under the Securities Act of 1933 on October 2, 2009, to register 7,500,000 Common Units that may be issued from time to time in connection with one or more acquisitions.

Description of Indebtedness

Our outstanding indebtedness was as follows:

	September 30, 2009	December 31, 2008
ETP Senior Notes	$ 5,050,000	$ 4,050,000
Transwestern Senior Notes	520,000	520,000
HOLP Senior Secured Notes	144,912	181,410
Revolving Credit Facilities	483,265	912,000
Other long-term debt	26,993	13,814
Unamortized discounts	(13,009)	(13,477)
Total Debt	$ 6,212,161	$ 5,663,747

The terms of our indebtedness and that of our Operating Companies are described in more detail in our Annual Report on Form 10-K for the year ended 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 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 September 30, 2009, there was a balance of $483.3 million outstanding on the ETP Credit Facility and taking into account letters of credit of approximately $65.1 million, $1.45 billion was available for future borrowings. The weighted average interest rate on the total amount outstanding at September 30, 2009, was 0.82%.

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 September 30, 2009. The amount available as of September 30, 2009 was $74.0 million.

Other

We have guaranteed 50% of the obligations of MEP under its 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 of September 30, 2009, MEP had $371.6 million 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 $185.8 million and $16.6 million, respectively, as of September 30, 2009.

In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by ETP or KMP. In October 2009, we made an additional capital contribution of $200 million to MEP, which MEP used to further reduce the outstanding borrowings under the MEP facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275 million.

In connection with acquisition of Energy Transfer Group, L.L.C. (see Note 17), we assumed $17.0 million of long-term debt during the third quarter of 2009.

Cash Distributions

We use cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders as well as to our General Partner in respect of its 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).

Distributions paid during the nine months ended September 30, 2009, as well as the amount paid in the aggregate for the general partner interest in the Partnership and the IDRs, are summarized as follows:

Quarter Ended	Record Date	Payment Date	Amount per Unit	Aggregate General Partner Interest and IDRs
December 31, 2008	February 6, 2009	February 13, 2009	$ 0.89375	$ 83,859
March 31, 2009	May 8, 2009	May 15, 2009	0.89375	89,006
June 30, 2009	August 7, 2009	August 14, 2009	0.89375	89,025

On October 28, 2009, we declared a cash distribution for the three months ended September 30, 2009 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on November 16, 2009 to Unitholders of record at the close of business on November 9, 2009.

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 September 30, 2009 were as follows:

	Commodity	Notional Volume	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	78,932,500	2009-2011	$ 16,291
Swing Swaps IFERC (MMBtu)	Natural Gas	(53,500,000)	2009-2010	3,389
Fixed Swaps/Futures (MMBtu)	Natural Gas	(3,755,000)	2009-2011	3,527
Forwards/Swaps (Gallons)	Propane/Ethane	11,718,000	2009-2010	2,447
Fair Value Hedging Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	(31,095,000)	2009-2010	$ (6,235)
Fixed Swaps/Futures (MMBtu)	Natural Gas	(31,967,500)	2009-2010	(7,341)
Cash Flow Hedging Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	(16,830,000)	2009-2010	$ (390)
Fixed Swaps/Futures (MMBtu)	Natural Gas	(27,625,000)	2009-2010	(18,675)
Forward/Swaps (Gallons)	Propane/Ethane	28,518,000	2009-2010	4,312

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 the year ended December 31, 2008.

Sensitivity Analysis

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

	Commodity	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark to Market Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	78,932,500	$ 16,291	$ 2,887
Swing Swaps IFERC (MMBtu)	Natural Gas	(53,500,000)	3,389	884
Fixed Swaps/Futures (MMBtu)	Natural Gas	(3,755,000)	3,527	2,931
Forwards/Swaps (Gallons)	Propane/Ethane	11,718,000	2,447	1,120
Fair Value Hedging Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	(31,095,000)	$ (6,235)	$ 411
Fixed Swaps/Futures (MMBtu)	Natural Gas	(31,967,500)	(7,341)	16,286
Cash Flow Hedging Derivatives				
Basis Swaps IFERC/NYMEX (MMBtu)	Natural Gas	(16,830,000)	$ (390)	$ 267
Fixed Swaps/Futures (MMBtu)	Natural Gas	(27,625,000)	(18,675)	16,459
Forwards/Swaps (Gallons)	Propane/Ethane	28,518,000	4,312	2,724

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

Interest Rate Risk

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 September 30, 2009, we had $483.3 million of variable rate debt outstanding and forward starting interest rate swaps with a notional amount of $500.0 million not designated as hedges. A hypothetical change of 100 basis points in the underlying interest rates on our variable rate debt would result in a net change in interest expense of approximately $4.8 million on an annual basis. Our non-hedged interest rate derivatives settle in December 2009, and a hypothetical decrease of 100 basis points in the LIBOR yield curve prior to settlement would result in unrealized losses of $44.6 million recorded in other income. Assuming corresponding parallel shifts in the LIBOR yield curve and the underlying interest rates on our variable rate debt, the decrease in interest expense from our variable rate debt would slightly offset the impact to net income from unrealized losses on our non-hedged interest rate derivatives.

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.

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 September 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 September 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Table of Contents

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the 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 quarter ended September 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 the year ended December 31, 2008.

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

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

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

(c) *Issuer Purchases of Equity Securities*. The following table discloses purchases of our Common Units made by us or on our behalf for the quarter ended September 30, 2009.

Period	Total Number of Units Purchased (1)	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Purchased Under the Plans or Programs
July 1 - July 31	7,997	$ 39.77	N/A	N/A
August 1 - August 31	2,393	44.51	N/A	N/A
September 1 - September 30	-	-	N/A	N/A
Total	10,390	40.86	N/A	N/A

(1) Pursuant to the terms of our equity incentive plans, to the extent the Partnership is required to withhold federal, state, local or foreign taxes in connection with any grant of an award, the issuance of ETP Common Units upon the vesting of an award, or payment made to a plan participant, it is a condition to the receipt of such payment that the plan participant make arrangements satisfactory to the Partnership for the payment of such taxes required to be withheld. A plan participant may relinquish such participant's right to a portion of the ETP Common Units to which they are entitled in connection with the issuance of ETP Common Units upon vesting of an award as payment for such taxes. During the three months ended September 30, 2009, certain of the participants in the 2004 Unit Plan elected to have a portion of the ETP Common Units to which they were entitled upon vesting of restricted units granted to them pursuant to the 2004 Unit Plan withheld by the Partnership to satisfy the Partnership's tax withholding obligations. None of the ETP Common Units were purchased by the Partnership through a publicly announced plan or program.

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.
(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.
(*)	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.

Table of Contents

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: November 9, 2009

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

Exhibit 31.1

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

I, Kelcy L. Warren, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

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

Exhibit 31.2

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

I, Martin Salinas, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

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

Exhibit 32.1

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

In connection with the quarterly report of Energy Transfer Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kelcy L. Warren, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: November 9, 2009

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

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

Exhibit 32.2

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

In connection with the quarterly report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Martin Salinas, Jr., Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: November 9, 2009

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

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