Energy Transfer Partners, L.P.
Form 10-Q
May 07, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2010

or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219

(Address of principal executive offices and zip code)

(214) 981-0700

(Registrant s telephone number, including area code)

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

Yes 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 May 4, 2010, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 191,240,470 Common Units

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FORM 10-Q

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

Forward-Looking Statements

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

Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management s control. For additional discussion of risks, uncertainties and assumptions, see Part II Other Information Item 1A. Risk Factors in this Quarterly Report on Form 10-Q as well as the Partnership s Report on Form 10-K for the year ended December 31, 2009 filed with the Securities and Exchange Commission (SEC) on February 24, 2010.

Definitions

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

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

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	March 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 384,297	$ 68,183
Marketable securities	3,726	6,055
Accounts receivable, net of allowance for doubtful accounts	490,475	566,522
Accounts receivable from related companies	52,192	57,369
Inventories	342,976	389,954
Exchanges receivable	7,815	23,136
Price risk management assets	19,575	12,371
Other current assets	115,581	148,373
Total current assets	1,416,637	1,271,963
PROPERTY, PLANT AND EQUIPMENT	9,839,358	9,649,405
ACCUMULATED DEPRECIATION	(1,055,151)	(979,158)
	8,784,207	8,670,247
ADVANCES TO AND INVESTMENTS IN AFFILIATES	653,390	663,298
GOODWILL	772,999	745,505
INTANGIBLES AND OTHER ASSETS, net	442,594	383,959
Total assets	$ 12,069,827	$ 11,734,972

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	March 31, 2010	December 31, 2009
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 344,739	$ 358,997
Accounts payable to related companies	20,850	38,842
Exchanges payable	9,545	19,203
Price risk management liabilities		442
Accrued and other current liabilities	366,557	365,168
Current maturities of long-term debt	40,853	40,887
Total current liabilities	782,544	823,539
LONG-TERM DEBT, less current maturities	6,014,898	6,176,918
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	20,347	
OTHER NON-CURRENT LIABILITIES	135,901	134,807
COMMITMENTS AND CONTINGENCIES (Note 14)		
	6,953,690	7,135,264
PARTNERS CAPITAL:		
General Partner	185,048	174,884
Limited Partners:		
Common Unitholders (190,823,837 and 179,274,747 units authorized, issued and outstanding at March 31, 2010 and December 31, 2009, respectively)	4,899,031	4,418,017
Class E Unitholders (8,853,832 units authorized, issued and outstanding held by subsidiary and reported as treasury units)		
Accumulated other comprehensive income	32,058	6,807
Total partners capital	5,116,137	4,599,708
Total liabilities and partners capital	$ 12,069,827	$ 11,734,972

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
REVENUES:		
Natural gas operations	$ 1,306,709	$ 1,111,955
Retail propane	533,439	487,907
Other	31,833	30,238
Total revenues	1,871,981	1,630,100
COSTS AND EXPENSES:		
Cost of products sold natural gas operations	912,606	732,113
Cost of products sold retail propane	304,981	220,222
Cost of products sold other	7,278	6,804
Operating expenses	170,748	181,773
Depreciation and amortization	83,276	72,603
Selling, general and administrative	48,754	55,732
Total costs and expenses	1,527,643	1,269,247
OPERATING INCOME	344,338	360,853
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(104,962)	(82,045)
Equity in earnings of affiliates	6,181	497
Losses on disposal of assets	(1,864)	(426)
Gains on non-hedged interest rate derivatives		13,726
Allowance for equity funds used during construction	1,309	20,427
Other, net	1,033	1,067
INCOME BEFORE INCOME TAX EXPENSE	246,035	314,099
Income tax expense	5,924	6,932
NET INCOME	240,111	307,167
GENERAL PARTNER S INTEREST IN NET INCOME	99,999	90,290
LIMITED PARTNERS INTEREST IN NET INCOME	$ 140,112	$ 216,877
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.74	$ 1.37
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	188,424,574	157,009,238

DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.74	$ 1.37
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	189,127,283	157,390,400

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

(unaudited)

	Three Months Ended March 31, 2010	2009
Net income	$ 240,111	$ 307,167
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(6,506)	(10,549)
Change in value of derivative instruments accounted for as cash flow hedges	34,086	(1,386)
Change in value of available-for-sale securities	(2,329)	51
	25,251	(11,884)
Comprehensive income	$ 265,362	$ 295,283

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE THREE MONTHS ENDED MARCH 31, 2010

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2009	$ 174,884	$ 4,418,017	$ 6,807	$ 4,599,708
Distributions to partners	(98,773)	(169,135)		(267,908)
Units issued for cash		504,480		504,480
Capital contribution from General Partner (payment of contributions receivable)	8,932			8,932
Distributions on unvested unit awards		(1,094)		(1,094)
Tax effect of remedial income allocation from tax amortization of goodwill		(851)		(851)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings		7,196		7,196
Non-cash executive compensation	6	306		312
Other comprehensive income			25,251	25,251
Net income	99,999	140,112		240,111
Balance, March 31, 2010	$ 185,048	$ 4,899,031	$ 32,058	$ 5,116,137

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Three Months Ended March 31, 2010	2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 500,783	$ 437,124
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(149,619)	(5,511)
Capital expenditures (excluding allowance for equity funds used during construction)	(119,721)	(263,819)
Contributions in aid of construction costs	2,174	1,877
Advances to affiliates, net of repayments	(50)	(119,850)
Proceeds from the sale of assets	1,074	2,925
Net cash used in investing activities	(266,142)	(384,378)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	77,967	487,388
Principal payments on debt	(241,998)	(525,802)
Net proceeds from issuance of Limited Partner units	504,480	225,863
Capital contribution from General Partner	8,932	
Distributions to partners	(267,908)	(225,968)
Debt issuance costs		(173)
Net cash provided by (used in) financing activities	81,473	(38,692)
INCREASE IN CASH AND CASH EQUIVALENTS	316,114	14,054
CASH AND CASH EQUIVALENTS, beginning of period	68,183	91,902
CASH AND CASH EQUIVALENTS, end of period	$ 384,297	$ 105,956

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

(unaudited)

1. OPERATIONS AND ORGANIZATION:

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

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

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

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

Business Operations

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

La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.

Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, LLC (ETC MEP), both 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.

ETC Compression, LLC (ETC Compression), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

Heritage Operating, L.P. (HOLP), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.

Titan Energy Partners, L.P. (Titan), a Delaware limited partnership also engaged in retail propane operations.

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

2. ESTIMATES:

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 months ended March 31, 2010 represent the actual results in all material respects.

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

3. ACQUISITIONS:

During the three months ended March 31, 2010, we purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, we recorded customer contracts of $68.2 million and goodwill of $27.3 million. See further discussion at note 7.

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

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

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

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

	Three Months Ended March 31, 2010	2009
Net income	$ 240,111	$ 307,167
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	83,276	72,603
Amortization of finance costs charged to interest	2,291	1,990
Provision for loss on accounts receivable	883	1,312
Non-cash unit-based compensation expense	7,196	6,801
Non-cash executive compensation expense	312	313
Deferred income taxes	1,433	6,719
Losses on disposal of assets	1,864	426
Allowance for equity funds used during construction	(1,309)	(20,427)
Distributions on unvested awards	(1,094)	(952)
Distributions in excess of equity in earnings of affiliates, net	10,109	328
Other non-cash	(116)	611
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	78,173	100,905
Accounts receivable from related companies	5,177	(15,895)
Inventories	46,978	127,742
Exchanges receivable	15,320	21,309
Other current assets	32,821	58,556
Intangibles and other assets	1,849	1,270
Accounts payable	(14,151)	(59,795)
Accounts payable to related companies	1,815	(16,004)
Exchanges payable	(9,658)	(26,484)
Accrued and other current liabilities	(41,036)	(72,798)
Other non-current liabilities	(368)	(187)
Price risk management liabilities, net	38,907	(58,386)
Net cash provided by operating activities	$ 500,783	$ 437,124

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

	Three Months Ended March 31, 2010	2009
NON-CASH INVESTING ACTIVITIES:		
Capital expenditures accrued	$ 68,436	$ 84,908
NON-CASH FINANCING ACTIVITIES:		
Capital contribution receivable from general partner	$	$ 4,795
SUPPLEMENTAL CASH FLOW INFORMATION:		

Cash paid for interest, net of interest capitalized	$	129,249	$	108,461
Cash received for income taxes	$	9,732	$	24

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5. ACCOUNTS RECEIVABLE:

Accounts receivable consisted of the following:

	March 31, 2010	December 31, 2009
Natural gas operations	$ 358,504	$ 429,849
Propane	138,336	143,011
Less allowance for doubtful accounts	(6,365)	(6,338)
Total, net	$ 490,475	$ 566,522

The activity in the allowance for doubtful accounts consisted of the following:

Balance, December 31, 2009	$ 6,338
Accounts receivable written off, net of recoveries	(856)
Provision for loss on accounts receivable	883
Balance, March 31, 2010	$ 6,365

6. INVENTORIES:

Inventories consisted of the following:

	March 31, 2010	December 31, 2009
Natural gas and NGLs, excluding propane	$ 33,930	$ 157,103
Propane	48,080	66,686
Appliances, parts and fittings and other	260,966	166,165
Total inventories	$ 342,976	$ 389,954

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

7. GOODWILL, INTANGIBLES AND OTHER ASSETS:

A net increase in goodwill of $27.5 million was recorded during the three months ended March 31, 2010, primarily due to $27.3 million from the acquisition of the natural gas gathering company referenced in Note 3, which is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $68.2 million with useful lives of 46 years.

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

	March 31, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (3 to 15 years)	$ 23,557	$ (12,588)	$ 24,139	$ (12,415)
Customer lists (3 to 30 years)	153,843	(56,485)	153,843	(53,123)
Contract rights (6 to 46 years)	91,265	(6,482)	23,015	(5,638)
Patents (9 years)	750	(56)	750	(35)
Other (10 to 15 years)	1,320	(414)	478	(397)
Total amortizable intangible assets	270,735	(76,025)	202,225	(71,608)
Non-amortizable intangible assets Trademarks	75,825		75,825	
Total intangible assets	346,560	(76,025)	278,050	(71,608)
Other assets:				
Financing costs (3 to 30 years)	68,657	(26,939)	68,597	(24,774)
Regulatory assets	101,895	(10,383)	101,879	(9,501)
Other	38,829		41,316	
Total intangibles and other assets	$ 555,941	$ (113,347)	$ 489,842	$ (105,883)

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

	Three Months Ended March 31,	
	2010	2009
Reported in depreciation and amortization	$ 5,146	$ 4,709
Reported in interest expense	$ 2,165	$ 1,878

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

Years Ending December 31:	
2011	$ 26,828
2012	23,243
2013	17,812
2014	16,802
2015	14,479

8. 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 March 31, 2010 was $6.72 billion and $6.06 billion, respectively. At December 31, 2009, the aggregate fair value and carrying amount of long-term debt was $6.75 billion and $6.22 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible level of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (OTC) commodity derivatives entered into directly with third parties as a Level 2

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valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

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

		Fair Value Measurements at March 31, 2010 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 3,726	$ 3,726	$
Interest rate swaps	193		193
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	16,761	16,749	12
Swing Swaps IFERC	2,147	2,147	
Fixed Swaps/Futures	28,572	28,572	
Options Puts	19,651		19,651
Propane/Ethane Forwards/Swaps	747		747
Total commodity derivatives	67,878	47,468	20,410
Total Assets	$ 71,797	$ 51,194	$ 20,603
Liabilities:			
Interest rate swaps	$ (1,646)	$	$ (1,646)
Commodity derivatives:			
Natural Gas:			
Swing Swaps IFERC	(79)		(79)
Options Calls	(5,351)		(5,351)
Total commodity derivatives	(5,430)		(5,430)
Total Liabilities	$ (7,076)	$	$ (7,076)

Fair Value Measurements at December 31, 2009 Using

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

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9. 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 current capacity of 1.4 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 capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is expected to be completed as early as June 2010. 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.

Fayetteville Express Pipeline LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Panola County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC (FEP), the entity formed to construct, own and operate this pipeline, received FERC approval of its application for authority to construct and operate this pipeline. That order is currently subject to a limited request for rehearing. The pipeline is expected to have an initial capacity of 2.0 Bcf/d and is expected to be in service by the end of 2010. As of March 31, 2010, 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.

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 March 31, 2010	2009
Revenue	$ 51,158	$
Operating income	21,727	
Net income	10,930	

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

10. NET INCOME PER LIMITED PARTNER UNIT:

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

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

	Three Months Ended March 31, 2010		Three Months Ended March 31, 2009	
Net income	$	240,111	$	307,167
General Partner s interest in net income		99,999		90,290
Limited Partners interest in net income		140,112		216,877
Additional earnings allocated from General Partner		812		
Distributions on employee unit awards, net of allocation to General Partner		(1,157)		(1,004)
Net income available to Limited Partners	$	139,767	$	215,873
Weighted average Limited Partner units basic		188,424,574		157,009,238
Basic net income per Limited Partner unit	$	0.74	$	1.37
Weighted average Limited Partner units		188,424,574		157,009,238
Dilutive effect of unit grants		702,709		381,162
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants		189,127,283		157,390,400
Diluted net income per Limited Partner unit	$	0.74	$	1.37

11. DEBT OBLIGATIONS:

Revolving Credit Facilities

ETP Credit Facility

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

As of March 31, 2010, there was no balance outstanding on the ETP Credit Facility, and taking into account letters of credit of approximately $62.2 million, $1.94 billion was available for future borrowings.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP s subsidiaries secure the HOLP Credit Facility. At March 31, 2010, there was no outstanding balance in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of March 31, 2010 was $74.0 million.

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Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at March 31, 2010.

12. PARTNERS CAPITAL:
Common Units Issued

The change in Common Units during the three months ended March 31, 2010 was as follows:

	Number of Units
Balance, December 31, 2009	179,274,747
Common Units issued in connection with public offerings	9,775,000
Common Units issued in connection with the Equity Distribution Agreement	1,760,783
Issuance of Common Units under equity incentive plans	13,307
Balance, March 31, 2010	190,823,837

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

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC (UBS). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During the three months ended March 31, 2010, we issued 1,760,783 of our Common Units pursuant to this agreement. In addition, we initiated trades on 326,633 of our Common Units that had not settled as of March 31, 2010. The proceeds of approximately $81.0 million, net of commissions, were used for general partnership purposes. Approximately $134.8 million remains available to be issued under the agreement as of March 31, 2010.

Quarterly Distributions of Available Cash

On February 15, 2010, we paid a cash distribution for the three months ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on February 8, 2010.

On April 27, 2010, we declared a cash distribution for the three months ended March 31, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on May 17, 2010 to Unitholders of record at the close of business on May 7, 2010.

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The total amounts of distributions declared during the three months ended March 31, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Three Months Ended March 31, 2010	2009
Limited Partners:		
Common Units	$ 170,921	$ 150,853
Class E Units	3,121	3,121
General Partner Interest	4,880	4,860
Incentive Distribution Rights	94,917	84,146
Total distributions declared by ETP	$ 273,839	$ 242,980

Accumulated Other Comprehensive Income

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

	March 31, 2010	December 31, 2009
Net gains on commodity related hedges	$ 29,642	$ 1,991
Net losses on interest rate hedges	(196)	(125)
Unrealized gains on available-for-sale securities	2,612	4,941
Total AOCI, net of tax	$ 32,058	$ 6,807

13. INCOME TAXES:

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

	Three Months Ended March 31, 2010	2009
Current expense (benefit):		
Federal	$ 1,318	$ (4,336)
State	3,173	3,518
Total	4,491	(818)
Deferred expense:		
Federal	1,418	7,101
State	15	649
Total	1,433	7,750
Total income tax expense	$ 5,924	$ 6,932

Effective tax rate	2.41%	2.21%

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.

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14. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:
Regulatory Matters

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

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

Guarantees

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the MEP Facility), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

The commitment amount under the MEP Facility was $255.4 million as of March 31, 2010 and it had $89.0 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 $44.5 million and $16.6 million, respectively, as of March 31, 2010. The weighted average interest rate on the total amount outstanding as of March 31, 2010 was 1.5%. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions.

FEP Guarantee

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

As of March 31, 2010, FEP had $468.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP s outstanding borrowings was $234.0 million as of March 31, 2010. The weighted average interest rate on the total amount outstanding as of March 31, 2010 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts. In addition, we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a contract to purchase not less than 90.0 million gallons per year that expires in 2015. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.9 million and $6.0 million for the three months ended March 31, 2010 and 2009, respectively.

Titan has an agreement with Enterprise (see Note 16) to purchase the majority of Titan s propane requirements. The contract expired in March 2010 and contains renewal and extension options that are currently under negotiation.

We have commitments to make capital contributions to our joint ventures. For the joint ventures that we currently have interests in, we expect that capital contributions for the remainder of 2010 will be between $100 million and $120 million.

Litigation and Contingencies

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

FERC/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 alleged that we violated this rule by artificially suppressing prices that were included in the Platts Inside FERC Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. 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. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC 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 FERC s Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC s Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement settles all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims 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 made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

We made the $5.0 million payment and established the $25.0 million fund in October 2009. The judge issued his report in March 2010 recommending the allocation of the $25.0 million fund. We expect a final decision on the allocation of the $25.0 million in 2010.

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, Texas.

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 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Briefing is complete and the case was argued before the Fifth Circuit on April 28, 2010.

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 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Briefing is now complete, and the case was argued before the Fifth Circuit on April 27, 2010.

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

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 March 31, 2010 and December 31, 2009, accruals of approximately $10.5 million and $11.1 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

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

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 $8.5 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

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

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

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

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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 March 31, 2010 or December 31, 2009 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

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 March 31, 2010 and December 31, 2009, accruals on an undiscounted basis of $12.6 million were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL 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 (DOT) under the Pipeline Hazardous Materials Safety Administration (PHMSA), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas. Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended March 31, 2010 and 2009, $1.4 million and $3.7 million, respectively, of capital costs and $1.9 million and $3.4 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

15. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.

We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage 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 inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread, through either mark-to-market or the physical withdrawal of natural gas.

We are also exposed to market risk on gas we retain for fees in our intrastate transportation and storage segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

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The following table details the outstanding commodity-related derivatives:

	March 31, 2010		December 31, 2009	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	47,882,500	2010-2011	72,325,000	2010-2011
Swing Swaps IFERC (MMBtu)	(6,465,000)	2010	(38,935,000)	2010
Fixed Swaps/Futures (MMBtu)	(14,775,000)	2010-2011	4,852,500	2010-2011
Options Puts (MMBtu)	(15,870,000)	2010	2,640,000	2010
Options Calls (MMBtu)	(22,580,000)	2010	(2,640,000)	2010
Propane/Ethane:				
Forwards/Swaps (Gallons)	42,000	2010	6,090,000	2010
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(3,602,500)	2010-2011	(22,625,000)	2010
Fixed Swaps/Futures (MMBtu)	(6,865,000)	2010-2011	(27,300,000)	2010
Hedged Item Inventory (MMBtu)	6,865,000	2010	27,300,000	2010
Cash Flow Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(9,625,000)	2010	(13,225,000)	2010
Fixed Swaps/Futures (MMBtu)	(16,500,000)	2010	(22,800,000)	2010
Options Puts (MMBtu)	22,200,000	2011		
Options Calls (MMBtu)	(22,200,000)	2011		
Propane/Ethane:				
Forwards/Swaps (Gallons)	6,636,000	2010-2011	20,538,000	2010

We expect gains of $24.5 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps to effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt into variable rate cash flows in order to achieve our desired mix of fixed and variable rate debt.

As of March 31, 2010, we have interest rate swaps with notional amount of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate of 6.00% and 5.95% that mature in July 2013 and February 2015, respectively. These swaps are accounted for as fair value hedges.

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Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2010	December 31, 2009	March 31, 2010	December 31, 2009
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 34,796	$ 669	$ (1,545)	$ (24,035)
Commodity derivatives	731	8,443		(201)
Interest rate swap derivatives	193		(1,646)	
	35,720	9,112	(3,191)	(24,236)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	87,959	72,851	(59,441)	(36,950)
Commodity derivatives	29	3,928	(79)	(241)
	87,988	76,779	(59,520)	(37,191)
Total derivatives	$ 123,708	$ 85,891	$ (62,711)	$ (61,427)

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

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

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $66.8 million and $79.7 million as of March 31, 2010 and December 31, 2009, respectively.

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

	Change in Value Recognized in OCI on Derivatives (Effective Portion)	
	Three Months Ended March 31,	
	2010	2009
Derivatives in cash flow hedging relationships:		
Commodity derivatives	$ 34,108	$ (1,386)
Interest rate swap derivatives		

Total	$ 34,108	$ (1,386)

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	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended March 31,	
		2010	2009
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$ 5,315	$ 10,477
Interest rate swap derivatives	Interest expense	71	72
Total		$ 5,386	$ 10,549

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion Three Months Ended March 31,	
		2010	2009
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$ 1,121	$
Interest rate swap derivatives	Interest expense		
Total		$ 1,121	$

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness Three Months Ended March 31,	
		2010	2009
Derivatives in fair value hedging relationships (including hedged item):			
Commodity derivatives	Cost of products sold	$ (7,384)	$
Interest rate swap derivatives	Interest expense		
Total		$ (7,384)	$

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives Three Months Ended March 31,	
		2010	2009
Derivatives not designated as hedging instruments:			
Commodity derivatives	Cost of products sold	$ 21,967	$ 51,437
Interest rate swap derivatives	Gains on non-hedged		13,726

	interest rate derivatives		
Total		$ 21,967	$ 65,163

We recognized $8.8 million and $73.2 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended March 31, 2010 and 2009, respectively.

Credit Risk

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

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on 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 consolidated balance sheet and recognized in net income or other comprehensive income.

16. RELATED PARTY TRANSACTIONS:

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

		Three Months Ended March 31,	
	Product	2010	2009
Natural Gas Operations:			
Sales	NGLs	$ 120,124	$ 63,194
	Natural gas	22,650	9,689
	Fees and other	1,946	1,600
Purchases	Natural Gas Imbalances	834	1,058
	Natural gas	5,632	12,548
	Fees	131	52
Propane Operations:			
Sales	Propane	789	6,282
	Derivatives	9,696	
Purchases	Propane	165,764	101,926
	Derivatives		33,292

Titan purchases the majority of its propane requirements from Enterprise pursuant to an agreement that expired in March 2010, and contains renewal and extension options that are currently under negotiation. As of December 31, 2009, Titan had forward mark-to-market derivatives for approximately 6.1 million gallons of propane at a fair value asset of $3.3 million with Enterprise. Substantially all of these forward contracts were settled as of March 31, 2010. In addition, as of March 31, 2010 and December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 6.6 million and 20.5 million gallons of propane at a fair value asset of $0.7 million and $8.4 million, respectively, with Enterprise.

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

	March 31, 2010	December 31, 2009
Natural Gas Operations:		
Accounts receivable	$ 41,754	$ 47,005
Accounts payable	224	3,518
Imbalance receivable (payable)	(112)	694
Propane Operations:		
Accounts receivable	2,338	3,386
Accounts payable	13,398	31,642

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

	March 31, 2010	December 31, 2009
ETP GP	$ 141	$ 221
ETE	6,495	5,255
MEP	945	632
Others	519	870
Total accounts receivable from related companies excluding Enterprise	$ 8,100	$ 6,978

17. REPORTABLE SEGMENTS:

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

natural gas operations:

o intrastate transportation and storage

o interstate transportation

o midstream

retail propane and other retail propane related operations

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$ 602,356	$ 455,803
Intersegment revenues	264,136	172,848
	866,492	628,651
Interstate transportation revenues from external customers	68,269	61,349
Midstream:		
Revenues from external customers	618,707	594,803
Intersegment revenues	178,064	36,829
	796,771	631,632
Retail propane and other retail propane related revenues from external customers	561,155	515,912
All other:		
Revenues from external customers	21,494	2,233
Intersegment revenues	1,446	
	22,940	2,233
Eliminations against operating expenses	(84)	
Eliminations against cost of products sold	(443,562)	(209,677)
Total revenues	$ 1,871,981	$ 1,630,100
Cost of products sold:		
Intrastate transportation and storage	$ 641,506	$ 382,614
Midstream	699,792	559,176
Retail propane and other retail propane related	309,757	225,105
All other	17,372	1,921
Eliminations	(443,562)	(209,677)
Total cost of products sold	$ 1,224,865	$ 959,139
Depreciation and amortization:		
Intrastate transportation and storage	$ 28,992	$ 25,033
Interstate transportation	12,451	10,659
Midstream	20,335	16,510
Retail propane and other retail propane related	20,088	20,272
All other	1,410	129
Total depreciation and amortization	$ 83,276	$ 72,603
Operating income (loss):		
Intrastate transportation and storage	$ 134,204	$ 143,715
Interstate transportation	31,597	28,195
Midstream	52,332	25,139
Retail propane and other retail propane related	126,774	164,069
All other	(1,131)	(766)

Selling, general and administrative expenses not allocated to segments		562		501
Total operating income	$	344,338	$	360,853

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	Three Months Ended March 31, 2010	2009
Other items not allocated by segment:		
Interest expense, net of interest capitalized	$ (104,962)	$ (82,045)
Equity in earnings of affiliates	6,181	497
Losses on disposal of assets	(1,864)	(426)
Gains on non-hedged interest rate derivatives		13,726
Allowance for equity funds used during construction	1,309	20,427
Other income, net	1,033	1,067
Income tax expense	(5,924)	(6,932)
	(104,227)	(53,686)
Net income	$ 240,111	$ 307,167

	As of March 31, 2010	As of December 31, 2009
Total assets:		
Intrastate transportation and storage	$ 4,700,694	$ 4,901,102
Interstate transportation	3,407,204	3,313,837
Midstream	1,661,886	1,523,538
Retail propane and other retail propane related	1,760,945	1,784,353
All other	539,098	212,142
Total	$ 12,069,827	$ 11,734,972

	Three Months Ended March 31, 2010	2009
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 25,619	$ 120,299
Interstate transportation	35,470	41,327
Midstream	114,865	27,133
Retail propane and other retail propane related	16,298	17,242
All other	2,412	1,576
Total	$ 194,664	$ 207,577

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

(Tabular dollar amounts are in thousands)

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 24, 2010. Our Management s Discussion and Analysis includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A. Risk Factors included in this report and in our Annual Report for the year ended December 31, 2009.

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

Overview

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

General

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

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

Our principal operations are conducted in the following segments:

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

We generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we utilize any excess storage capacity to inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the

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hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains.

In addition to hedging our stored natural gas, we also use financial derivatives to lock in prices on a portion of our estimated volumes exposed to natural gas price risk within our intrastate transportation segment.

During 2010, we continued to enter into financial derivatives to lock in spreads on a portion of our transportation system s open capacity. Margins earned on that open capacity are dependent on price differentials at different points on our system, generally from West Texas to East Texas. We account for these financial derivatives using mark-to-market accounting and the change in value of these derivatives are recorded in earnings. As of March 31, 2010, approximately 19% of our intrastate transportation capacity is hedged.

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

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

In addition to fee-based contracts for gathering, treating and processing, we also have percent of proceeds and keep-whole contracts, which are subject to market pricing. For percent of proceeds contracts (which accounted for approximately 11% of total processed volumes for the three months ended March 31, 2010 and 2009, respectively), we retain a portion of the natural gas and NGLs processed as a fee. When natural gas and NGL pricing increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGL s decrease, so does the value of the portion we retain as a fee. For keep-whole contracts (which accounted for approximately 34% and 26% of total processed volumes for the three months ended March 31, 2010 and 2009, respectively), we retain the difference between the price of NGLs and the cost of the gas to process it. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could be negative. In the event it is uneconomical to process this gas, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs.

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

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

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Results of Operations

Consolidated Results

	Three Months Ended March 31, 2010	2009	Change
Revenues	$ 1,871,981	$ 1,630,100	$ 241,881
Cost of products sold	1,224,865	959,139	265,726
Gross margin	647,116	670,961	(23,845)
Operating expenses	170,748	181,773	(11,025)
Depreciation and amortization	83,276	72,603	10,673
Selling, general and administrative	48,754	55,732	(6,978)
Operating income	344,338	360,853	(16,515)
Interest expense, net of interest capitalized	(104,962)	(82,045)	(22,917)
Equity in earnings of affiliates	6,181	497	5,684
Losses on disposal of assets	(1,864)	(426)	(1,438)
Gains on non-hedged interest rate derivatives		13,726	(13,726)
Allowance for equity funds used during construction	1,309	20,427	(19,118)
Other, net	1,033	1,067	(34)
Income tax expense	(5,924)	(6,932)	1,008
Net income	$ 240,111	$ 307,167	$ (67,056)

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

Interest Expense. Interest expense increased principally due to issuances of senior notes in April and December 2009. Proceeds from the issuance of these notes were primarily used to finance growth capital expenditures 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 $1.1 million and $5.9 million for the three months ended March 31, 2010 and 2009, respectively.

Equity in Earnings of Affiliates. The increase in equity in earnings of affiliates between the periods was primarily attributable to earnings of MEP, which was placed in service in 2009 (the first Zone in April 2009 and the second Zone in August 2009). We recorded equity in earnings of MEP of $5.5 million during 2010.

Gains on Non-Hedged Interest Rate Derivatives. The decrease in gains on non-hedged interest rate derivatives was due to the settlement of all of our non-hedged interest rate swaps during 2009. As of March 31, 2009, we had outstanding interest rate swaps with a notional amount of $750 million for which we did not apply hedge accounting; however, all of our interest rate swaps were accounted for as fair value hedges during the three months ended March 31, 2010.

Allowance for Equity Funds Used During Construction. The decrease in AFUDC on equity is due to the Phoenix project which was completed in February 2009. AFUDC on equity amounts recorded in property, plant and equipment (excluding AFUDC gross-up) were $1.3 million and $12.5 million for the three months ended March 31, 2010 and 2009, respectively.

Segment Operating Results

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

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

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Operating income (loss) by segment is as follows:

	Three Months Ended March 31, 2010	2009	Change
Intrastate transportation and storage	$ 134,204	$ 143,715	$ (9,511)
Interstate transportation	31,597	28,195	3,402
Midstream	52,332	25,139	27,193
Retail propane and other retail propane related	126,774	164,069	(37,295)
All other	(1,131)	(766)	(365)
Unallocated selling, general and administrative expenses	562	501	61
Operating income	$ 344,338	$ 360,853	$ (16,515)

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses are allocated monthly to the Operating Companies using the Modified Massachusetts Formula Calculation (MMFC). The expenses subject to allocation are based on estimated amounts and take into consideration 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 March 31, 2010	2009	Change
Natural gas MMBtu/d transported	11,354,270	13,623,212	(2,268,942)
Natural gas MMBtu/d sold	1,445,136	941,533	503,603
Revenues	$ 866,492	$ 628,651	$ 237,841
Cost of products sold	641,506	382,614	258,892
Gross margin	224,986	246,037	(21,051)
Operating expenses	41,961	53,490	(11,529)
Depreciation and amortization	28,992	25,033	3,959
Selling, general and administrative	19,829	23,799	(3,970)
Segment operating income	$ 134,204	$ 143,715	$ (9,511)

Volumes. We experienced a decrease in volumes transported on our intrastate transportation systems due to less drilling activity and production by our customers in areas where our assets are located due to the low natural gas price environment and less favorable basis differentials. The increase in natural gas sold was a result of more withdrawals out of our Bammel storage facility as well as additional efforts to optimize our assets.

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

	Three Months Ended March 31, 2010	2009	Change
Transportation fees	$ 140,798	$ 175,133	$ (34,335)
Natural gas sales and other	40,010	18,702	21,308
Retained fuel revenues	35,702	35,177	525
Storage margin, including fees	8,476	17,025	(8,549)

Total gross margin	$ 224,986	$ 246,037	$ (21,051)

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

Volumes on our transportation pipelines decreased, resulting in a decrease in transportation fees of $34.3 million. This decrease primarily resulted from a narrowing of basis differentials between the west and east Texas market hubs, with the average spot price difference between these locations decreasing to $0.05/MMBtu from $0.62/MMBtu in the prior period.

Margin from natural gas sales and other activity increased by $21.3 million during the period primarily due to favorable impacts from system optimization activities. Excluding the derivatives related to storage, we recognized unrealized gains of $4.9 million for the three months ended March 31, 2010 compared to unrealized gains of $2.6 million for the three months ended March 31, 2009.

While our transported volumes were down and we retained less natural gas during the period, our retention revenue increased by $0.5 million principally due to more favorable pricing. Our average retention price during the period ended March 31, 2010 was $4.42/MMBtu compared to $3.31/MMBtu for the period ended March 31, 2009.

Storage margin decreased by $8.5 million, primarily due to less price variance between the carrying cost of our inventory and the locked-in sales price of our financial derivative. We apply fair value hedge accounting to the natural gas we purchase for storage and adjust the carrying amount to the spot price at the end of each period. Most of the margin that we realized for the natural gas that was withdrawn during the three months ended March 31, 2010 had been previously recognized through fair value adjustments and was therefore not reflected in the current period. The margin we recognized during the period was the remainder of the spread originally locked-in. Natural gas prices rose leading up to and during the withdrawal season. Therefore, we sold the natural gas to capture the margin on our gas held in storage. In the comparable period last year, it was advantageous to recognize the locked-in spread on the derivatives used to hedge the inventory and postpone the withdrawal as natural gas prices were declining.

Storage margin was comprised of the following:

	Three Months Ended March 31, 2010	2009
Withdrawals from storage natural gas inventory (MMBtu)	27,016,787	11,254,403
Margin on physical sales	$ 64,378	$ (11,166)
Fair value/lower of cost or market adjustment	(68,555)	(44,621)
Settlements of financial derivatives	(10,499)	166,246
Unrealized gains (losses) on derivatives	13,118	(99,907)
Net impact of natural gas inventory transactions	(1,558)	10,552
Revenues from fee-based storage	11,299	8,342
Other costs	(1,265)	(1,869)
Total storage margin	$ 8,476	$ 17,025

Operating Expenses. Intrastate operating expenses primarily decreased between the periods due to a decrease in consumption expense of $7.8 million. Additionally, we experienced lower ad valorem expenses of $1.4 million, lower compressor maintenance expense of $1.2 million and lower electricity expense of $1.1 million as compared to the prior period.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased primarily due to the completion of projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative. Intrastate selling, general and administrative expenses decreased between the periods as a result of a decrease in professional fees of $6.3 million offset by an increase in employee-related costs (including allocated overhead) of $2.4 million.

Interstate Transportation

		Three Months Ended March 31, 2010	2009	Change
Natural gas MMBtu/d	transported	1,557,921	1,747,560	(189,639)
Natural gas MMBtu/d	sold	20,043	15,044	4,999

Revenues	$ 68,269	$ 61,349	$ 6,920
Operating expenses	16,061	15,365	696
Depreciation and amortization	12,451	10,659	1,792
Selling, general and administrative	8,160	7,130	1,030
Segment operating income	$ 31,597	$ 28,195	$ 3,402

The interstate transportation segment data presented above does not include our interstate pipeline joint ventures, for which we reflect our proportionate share of income within Equity in earnings of affiliates below operating income in our condensed consolidated statement of operations. During the three months ended March 31, 2010, we recognized $5.5 million in equity in earnings primarily related to our 50% joint venture investment in MEP.

Volumes. Transported volumes decreased as compared to the prior period primarily as a result of less favorable market conditions for transporting natural gas principally from the San Juan Basin to East delivery points.

Revenues. Interstate transportation revenues increased between the periods by approximately $1.6 million as a result of the completion of the Phoenix project in February 2009 and a $5.3 million increase in operational sales revenues due to increases in natural gas prices and volume sold.

Operating Expenses. Operating expenses increased between the periods primarily due to an increase in ad valorem taxes resulting from increased property values related to the Phoenix pipeline expansion. This increase was partially offset by a net decrease in other operating expenses primarily due to lower electric demand costs resulting from lower throughput.

Depreciation and Amortization. Depreciation and amortization expense increased between the periods primarily due to incremental depreciation associated with the completion of the Phoenix pipeline expansion.

Selling, General and Administrative. Selling, general and administrative expenses increased between the periods primarily due to increased administrative expense allocation offset by decreased employee-related costs.

Midstream

	Three Months Ended March 31,		
	2010	2009	Change
Natural gas sold (MMBtu/d)	697,644	1,091,391	(393,747)
NGLs produced (Bbls/d)	48,312	46,580	1,732
Revenues	$ 796,771	$ 631,632	$ 165,139
Cost of products sold	699,792	559,176	140,616
Gross margin	96,979	72,456	24,523
Operating expenses	17,830	17,793	37
Depreciation and amortization	20,335	16,510	3,825
Selling, general and administrative	6,482	13,014	(6,532)
Segment operating income	$ 52,332	$ 25,139	$ 27,193

Volumes. NGL production increased between periods primarily due to increased inlet volumes at our Godley plant as a result of favorable NGL prices. The decrease in natural gas sold during the period primarily reflects decreased marketing activities resulting from less favorable market conditions.

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

Gross Margin.

	Three Months Ended March 31,		
	2010	2009	Change
Gathering and processing fee-based revenues	$ 54,294	$ 47,908	$ 6,386

Non fee-based contracts and processing	47,271	17,207	30,064
Other	(4,586)	7,341	(11,927)
Total gross margin	$ 96,979	$ 72,456	$ 24,523

Midstream gross margin increased primarily due to favorable NGL pricing. Our non fee-based processing agreements, which accounted for 46% of processed volumes during the three months ended March 31, 2010, benefited from higher NGL pricing. The composite NGL price increased to $1.09 per gallon from $0.60 per gallon in the prior period. The increase in NGL volumes that we received as fees for processing, as well as more favorable pricing, resulted in an increase in our non fee-based margin of $30.0 million. Total plant production also increased slightly in the period ended March 31, 2010. In addition, acquisitions and other growth capital expenditures located in Louisiana provided an increase in our fee-based margin of $6.4 million.

The decrease in other midstream gross margin reflects a decrease of $11.9 million from marketing activities due to less favorable market conditions compared to the prior year. We also recognized unrealized losses of $2.9 million for the three months ended March 31, 2010 compared to $11.2 million in the comparable period.

Operating Expenses. No significant changes occurred in midstream operating expenses compared to the prior period.

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

Selling, General and Administrative. Midstream selling, general and administrative expenses decreased between the periods primarily due to a decrease in employee-related costs (including allocated overhead expenses) of approximately $4.4 million and a decrease in professional fees of $2.1 million.

Retail Propane and Other Retail Propane Related

	Three Months Ended March 31,		
	2010	2009	Change
Retail propane gallons (in thousands)	217,611	218,480	(869)
Retail propane revenues	$ 533,439	$ 487,907	$ 45,532
Other retail propane related revenues	27,716	28,005	(289)
Retail propane cost of products sold	304,981	220,222	84,759
Other retail propane related cost of products sold	4,776	4,883	(107)
Gross margin	251,398	290,807	(39,409)
Operating expenses	91,732	94,176	(2,444)
Depreciation and amortization	20,088	20,272	(184)
Selling, general and administrative	12,804	12,290	514
Segment operating income	$ 126,774	$ 164,069	$ (37,295)

Volumes. Despite continued effects of customer conservation and the impact of the economic recession, retail propane volumes decreased only slightly. Volumes were favorably impacted by weather which was approximately 5.3% colder than normal as compared to weather which was 2.4% colder than normal during the same period in 2009. We use information gathered on temperatures based on heating degree days from information published by the National Oceanic and Atmospheric Administration (NOAA) to also analyze how our volume sales are affected by temperature. Our normal temperatures are based on the average heating degree days provided by NOAA for various data points in our operating areas for the 10-year period ending March 2010. Based on this information we calculate a ratio of actual heating degree days to normal heating degree days.

Gross Margin. Revenues increased period over period due to increases in average wholesale propane commodity prices. In addition, to hedge a significant portion of our propane sales commitments entered into under our customer prebuy programs, we utilize financial instruments to lock in margins. Prior to April 2009, these financial instruments were not designated as cash flow hedges for accounting purposes, and changes in market value were recorded in cost of products sold in the condensed consolidated statements of operations. During the three month period ended March 31, 2009, our propane margins were positively impacted by the settlement of financial instruments related to sales commitments that were entered into in 2008. Having recognized unrealized losses of $45.6 million on these financial instruments during 2008, we recognized unrealized gains of $35.0 million during the period ended March 31, 2009 as the contracts settled in the period. In comparison, only $3.3 million of unrealized gains were recognized during 2009 and settled as unrealized losses during the period ended March 31, 2010. Excluding the impact of the mark-to-market accounting, gross margins were consistent period over period.

Operating Expenses. Operating expenses decreased primarily due to a decrease in our operational employee incentive program of $4.5 million which was partially offset by increases in vehicle fuel expenses of $1.4 million and increases in business insurance reserves and claims of $1.0 million.

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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 $180 million and $200 million for the remainder of 2010;

- growth capital expenditures for our interstate transportation segment, excluding capital contributions to our joint ventures as discussed below, for the construction of new pipelines for which we expect to spend between $820 million and $890 million for the remainder of 2010;

- growth capital expenditures for our retail propane segment of between $20 million and $30 million for the remainder of 2010; and

- maintenance capital expenditures of between $70 million and $90 million for the remainder of 2010, which include (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; and (iii) capital expenditures for our propane operations to extend the useful lives of our existing propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet.

In addition to the capital expenditures noted above, we expect that capital contributions on the joint ventures that we currently have interests in will be between $100 million and $120 million for the remainder of 2010.

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

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

We raised approximately $423.6 million in net proceeds from our Common Unit offering in January 2010. In addition, we raised $81.0 million in net proceeds during the three months ended March 31, 2010 under an equity distribution program, as described in Note 12 to our condensed consolidated financial statements. As of March 31, 2010, in addition to approximately $384.3 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.94 billion. Based on our current estimates, we expect to utilize these resources, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2010; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Cash Flows

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

Operating Activities

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

Three months ended March 31, 2010 compared to three months ended March 31, 2009. Cash provided by operating activities during 2010 was $500.8 million as compared to $437.1 million for 2009. Net income was $240.1 million and $307.2 million for 2010 and 2009, respectively. The difference between net income and the net cash provided by operating activities consisted of non-cash items totaling $105.9 million and $70.7 million and changes in operating assets and liabilities of $155.8 million and $60.2 million for 2010 and 2009, respectively.

The non-cash activity in 2010 and 2009 consisted primarily of depreciation and amortization of $83.3 million and $72.6 million, respectively. In addition, non-cash compensation expense was $7.5 million and $7.1 million for 2010 and 2009, respectively. We also received distributions from our affiliates during 2010 that exceeded our equity in earnings by $10.1 million. These amounts are partially offset by the allowance for equity funds used during construction of $1.3 million and $20.4 million for 2010 and 2009, respectively.

Investing Activities

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

Three months ended March 31, 2010 compared to three months ended March 31, 2009. Cash used in investing activities during 2010 was $266.1 million as compared to $384.4 million for 2009. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2010 were $119.7 million, net of changes in accruals of $22.2 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2009 of $263.8 million, including changes in accruals of $71.3 million. In addition, in 2010 we paid cash for acquisitions of $149.6 million and made advances to our joint ventures of $0.1 million. We paid cash for acquisitions of $5.5 million and made advances to our joint ventures of $119.9 million ($111.0 million to MEP and $8.9 million to FEP) during 2009.

Growth capital expenditures for 2010, before changes in accruals, were $81.9 million for our midstream and intrastate transportation and storage segments, $30.5 million for our interstate transportation segment, and $9.9 million for our retail propane segment and all other. We also incurred $19.6 million of maintenance capital expenditures, of which $7.6 million related to our midstream and intrastate transportation and storage segments, $3.7 million related to our interstate segment and $8.3 million related to our retail propane segment and all other.

Growth capital expenditures for 2009, before changes in accruals, were $136.7 million for our midstream and intrastate transportation and storage segments, $28.9 million for our interstate transportation segment, and $12.3 million for our retail propane segment and all other. We also incurred $14.6 million in maintenance expenditures, of which $8.1 million related to our midstream and intrastate transportation and storage segments and $6.5 million related to our retail propane segment.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, as discussed below under Financing and Sources of Liquidity, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increase between the periods based on increases in the number of Common Units outstanding, as discussed below under Cash Distributions.

Three months ended March 31, 2010 compared to three months ended March 31, 2009. Cash provided by financing activities during 2010 was $81.5 million as compared to cash received in financing activities of $38.7 million for 2009. In 2010, we received $504.5 million in net proceeds from Common Unit offerings, including $81.0 million under our equity distribution program, as compared to $225.9 million in 2009 (see Note 12 to our condensed consolidated financial statements). Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint ventures, as well as for general partnership purposes. During 2010, we had a net decrease in our debt level of $164.0 million as compared to a net decrease of $38.4 million for 2009. In addition, we paid distributions of $267.9 million to our partners in 2010 as compared to $226.0 million in 2009.

Financing and Sources of Liquidity

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

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC (UBS). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During the three months ended March 31, 2010, we issued 1,760,783 of our Common Units pursuant to this agreement. In addition, we initiated trades on 326,633 of our Common Units that had not settled as of March 31, 2010. The proceeds of approximately $81.0 million, net of commissions, were used for general partnership purposes. Approximately $134.8 million remains available to be issued under the agreement as of March 31, 2010.

Description of Indebtedness

Our outstanding indebtedness was as follows:

	March 31, 2010	December 31, 2009
ETP Senior Notes	$ 5,050,000	$ 5,050,000
Transwestern Senior Unsecured Notes	870,000	870,000
HOLP Senior Secured Notes	140,512	140,512
Revolving credit facilities		160,000
Other long-term debt	9,337	10,122
Unamortized discounts	(12,645)	(12,829)
Fair value adjustments related to interest rate swaps	(1,453)	
Total debt	$ 6,055,751	$ 6,217,805

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, 2009, filed with the SEC on February 24, 2010.

Revolving Credit Facilities

ETP Credit Facility

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

As of March 31, 2010, there was no balance outstanding on the ETP Credit Facility, and taking into account letters of credit of approximately $62.2 million, $1.94 billion was available for future borrowings.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the HOLP Credit Facility) available 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 March 31, 2010, there was no outstanding balance in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of March 31, 2010 was $74.0 million.

Other

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the MEP Facility), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

The commitment amount under the MEP Facility was $255.4 million as of March 31, 2010 and it had $89.0 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 $44.5 million and $16.6 million, respectively, as of March 31, 2010. The weighted average interest rate on the total amount outstanding as of March 31, 2010 was 1.5%. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions.

FEP Guarantee

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

As of March 31, 2010, FEP had $468.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP s outstanding borrowings was $234.0 million as of March 31, 2010. The weighted average interest rate on the total amount outstanding as of March 31, 2010 was 3.2%.

Debt Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at March 31, 2010.

Cash Distributions

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

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On February 15, 2010, we paid a cash distribution for the three months ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on February 8, 2010.

On April 27, 2010, we declared a cash distribution for the three months ended March 31, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on May 17, 2010 to Unitholders of record at the close of business on May 7, 2010.

The total amounts of distributions declared during the three months ended March 31, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Three Months Ended March 31,	
	2010	2009
Limited Partners:		
Common Units	$ 170,921	$ 150,853
Class E Units	3,121	3,121
General Partner Interest	4,880	4,860
Incentive Distribution Rights	94,917	84,146
Total distributions declared by ETP	$ 273,839	$ 242,980

New Accounting Standards and Critical Accounting Policies

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2009, in addition to the interim unaudited condensed consolidated financial statements, accompanying notes and management s discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K. Since December 31, 2009, there have been no material changes to our primary market risk exposures or how those exposures are managed.

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Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of March 31, 2010 and December 31, 2009, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas and gallons for propane/ethane. Dollar amounts are presented in thousands.

	March 31, 2010			December 31, 2009		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark to Market Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	47,882,500	$ 18,215	$ 63	72,325,000	$ 24,554	$ 491
Swing Swaps IFERC	(6,465,000)	2,069	3,110	(38,935,000)	1,718	2,142
Fixed Swaps/Futures	(14,775,000)	1,642	6,517	4,852,500	9,949	3,126
Options Puts	(15,870,000)	15,779	582	2,640,000	837	447
Options Calls	(22,580,000)	(9,253)	153	(2,640,000)	(819)	314
Propane/Ethane:						
Forwards/Swaps	42,000	16	5	6,090,000	3,348	785
Fair Value Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(3,602,500)	72	6	(22,625,000)	(4,178)	2
Fixed Swaps/Futures	(6,865,000)	3,089	2,890	(27,300,000)	(13,285)	15,669
Cash Flow Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(9,625,000)	(1,525)	30	(13,225,000)	(1,640)	81
Fixed Swaps/Futures	(16,500,000)	23,841	7,042	(22,800,000)	(4,464)	13,197
Options Puts	22,200,000	3,872	4,556			
Options Calls	(22,200,000)	3,902	2,176			
Propane/Ethane:						
Forwards/Swaps	6,636,000	731	740	20,538,000	8,443	2,609

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

Interest Rate Risk

As of March 31, 2010, we had no variable rate debt outstanding, but we had $1.1 billion of our fixed rate debt swapped to a variable rate using interest rate derivatives. These interest rate derivatives are accounted for as fair value hedges of the fixed rate debt. A hypothetical change of 100 basis points in interest rates would result in a change to interest expense of approximately $11.0 million annually.

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Credit Risk

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

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

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

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of senior management, including the Chief Executive Officer (Principal Executive Officer) and the Chief Financial Officer (Principal Financial Officer) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a 15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of March 31, 2010 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive and Principal Financial Officers of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended March 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2009 and Note 14 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 March 31, 2010.

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, 2009.

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

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

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

(c) *Issuer Purchases of Equity Securities.* The following table discloses purchases of our Common Units made by us or on our behalf for the three months ended March 31, 2010.

Period	Total Number of Units Purchased (1)	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Yet Be Purchased Under the Plans or Programs
January 1 January 31	262	$ 44.65	N/A	N/A
February 1 February 28	131	45.73	N/A	N/A
March 1 March 31			N/A	N/A
Total	393	45.01	N/A	N/A

(1) Pursuant to the terms of our equity incentive plans, to the extent the Partnership is required to withhold federal, state, local or foreign taxes in connection with any grant of an award, the issuance of Common Units upon the vesting of an award, or payment made to a plan participant, it is a condition to the receipt of such payment that the plan participant make arrangements satisfactory to the Partnership for the payment of taxes. A plan participant may relinquish a portion of the Common Units to which the participant is entitled in connection with the issuance of Common Units upon vesting of an award as payment for such taxes. During the three months ended March 31, 2010, certain of the participants in the 2004 Unit Plan and the 2008 Long-Term Incentive Plan elected to have a portion of the Common Units to which they were entitled upon vesting of restricted units withheld by the Partnership to satisfy the Partnership s tax withholding obligations. None of the Common Units delivered to recipients of unit awards upon vesting were purchased by the Partnership through a publicly announced open-market plan or program.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 5. OTHER INFORMATION

Deferred Compensation Plan

Effective January 1, 2010, we adopted the Energy Transfer Partners Deferred Compensation Plan (the Plan). This voluntary, nonqualified Plan allows a select group of management and highly-compensated employees to elect to defer receipt of certain compensation. Each of our named executive officers is eligible to participate in the Plan; however, since 2007, Mr. Warren has voluntarily elected not to accept any salary, bonus, or equity incentive compensation and thus will not participate in the Plan. Participants may elect to defer up to 50% of their base salary, cash bonus and/or cash distributions paid with respect to unvested unit-based awards granted under our long-term incentive plan (the Deferred Amounts) and may choose from various investment options in which the Deferred Amounts are notionally invested. The Plan is funded by a grantor trust established by the Partnership, but Plan assets remain subject to the claims of our general creditors. The Deferred Amounts and any related investment earnings are payable (in a lump sum and/or installments) upon the termination of a participant s employment for any reason, a change in control, a specified date, and/or death, as specified by the participant. If a participant terminates or dies prior to the elected distribution date, his benefits will be paid upon termination in the form previously elected or, if applicable, upon death as a lump sum. A participant may also receive a distribution in the case of specified financial hardships, with the consent of the Plan s administrative committee. The Plan is intended to comply with section 409A of the Internal Revenue Code of 1986, as amended.

A copy of the Plan is attached as Exhibit 10.1 hereto and incorporated herein by reference. The foregoing summary of certain provisions of the Plan is qualified in its entirety by reference to such Plan document.

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.) dated as of July 28, 2009.
(2)	3.2	Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(3)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(4)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(6)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(6)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(5)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(7)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(7)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(*)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
(*)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
(*)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
(*)	10.1	Energy Transfer Partners Deferred Compensation Plan.
(*)	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.

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(**)	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.

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SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

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

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

Date: May 7, 2010

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

behalf of the registrant)