Energy Transfer Partners, L.P.
Form 10-Q
May 06, 2011
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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, 2011

or

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

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219

(Address of principal executive offices) (zip code)

(214) 981-0700

(Registrant s telephone number, including area code)

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

Yes 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes x 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 2, 2011, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 208,470,929 Common Units

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FORM 10-Q

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Energy Transfer Partners, L.P. and Subsidiaries

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (Energy Transfer Partners or the Partnership) in periodic press releases and some oral statements of the Partnership s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as anticipate, believe, intend, project, plan, expect continue, est forecast, may, will or similar expressions help identify forward-looking statements. Although the Partnership and its general partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership s actual results may vary materially from those anticipated, projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management s control. For additional discussion of risks, uncertainties and assumptions, see Part II Other Information Item 1A. Risk Factors in this Quarterly Report on Form 10-Q as well as Part I Item 1A. Risk Factors in the Partnership s Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission (SEC) on February 28, 2011.

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, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 60,138	$ 49,540
Marketable securities	2,640	2,032
Accounts receivable, net of allowance for doubtful accounts of $6,461 and $6,409 as of March 31, 2011 and December 31, 2010, respectively	492,324	503,129
Accounts receivable from related companies	78,552	53,866
Inventories	296,211	362,058
Exchanges receivable	16,493	21,823
Price risk management assets	12,780	13,706
Other current assets	149,844	115,269
Total current assets	1,108,982	1,121,423
PROPERTY, PLANT AND EQUIPMENT	11,285,766	11,087,468
ACCUMULATED DEPRECIATION	(1,373,800)	(1,286,099)
	9,911,966	9,801,369
ADVANCES TO AND INVESTMENTS IN AFFILIATES	19,677	8,723
LONG-TERM PRICE RISK MANAGEMENT ASSETS	16,256	13,948
GOODWILL	781,233	781,233
INTANGIBLES AND OTHER ASSETS, net	413,332	423,296
Total assets	$ 12,251,446	$ 12,149,992

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, 2011	December 31, 2010
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 274,598	$ 301,997
Accounts payable to related companies	21,079	27,177
Exchanges payable	20,297	15,451
Accrued and other current liabilities	396,218	462,560
Current maturities of long-term debt	35,080	35,265
Total current liabilities	747,272	842,450
LONG-TERM DEBT, less current maturities	6,554,271	6,404,916
LONG-TERM PRICE MANAGEMENT LIABILITIES	24,156	18,338
OTHER NON-CURRENT LIABILITIES	155,281	140,851
COMMITMENTS AND CONTINGENCIES (Note 13)		
PARTNERS CAPITAL:		
General Partner	181,139	174,618
Limited Partners:		
Common Unitholders (194,268,429 and 193,212,590 units authorized, issued and outstanding at March 31, 2011 and December 31, 2010, respectively)	4,573,365	4,542,656
Class E Unitholders (8,853,832 units authorized, issued and outstanding held by subsidiary and reported as treasury units)		
Accumulated other comprehensive income	15,962	26,163
Total partners capital	4,770,466	4,743,437
Total liabilities and partners capital	$ 12,251,446	$ 12,149,992

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

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, 2011	Three Months Ended March 31, 2010
REVENUES:		
Natural gas operations	$ 1,127,414	$ 1,306,709
Retail propane	528,466	533,439
Other	31,697	31,833
Total revenues	1,687,577	1,871,981
COSTS AND EXPENSES:		
Cost of products sold natural gas operations	676,800	912,606
Cost of products sold retail propane	310,864	304,981
Cost of products sold other	6,793	7,278
Operating expenses	188,489	170,748
Depreciation and amortization	95,964	83,276
Selling, general and administrative	45,532	48,754
Total costs and expenses	1,324,442	1,527,643
OPERATING INCOME	363,135	344,338
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(107,240)	(104,962)
Equity in earnings of affiliates	1,633	6,181
Losses on disposal of assets	(1,726)	(1,864)
Gains on non-hedged interest rate derivatives	1,779	
Other, net	218	2,342
INCOME BEFORE INCOME TAX EXPENSE	257,799	246,035
Income tax expense	10,597	5,924
NET INCOME	247,202	240,111
GENERAL PARTNER S INTEREST IN NET INCOME	107,539	99,999
LIMITED PARTNERS INTEREST IN NET INCOME	$ 139,663	$ 140,112
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.71	$ 0.74
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	193,821,128	188,424,574

DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.71	$ 0.74
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	194,526,600	189,127,283

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 STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

(unaudited)

	Three Months Ended March 31,	
	2011	2010
Net income	$ 247,202	$ 240,111
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(16,968)	(6,506)
Change in value of derivative instruments accounted for as cash flow hedges	6,159	34,086
Change in value of available-for-sale securities	608	(2,329)
	(10,201)	25,251
Comprehensive income	$ 237,001	$ 265,362

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, 2011

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2010	$ 174,618	$ 4,542,656	$ 26,163	$ 4,743,437
Distributions to partners	(101,024)	(173,184)		(274,208)
Units issued for cash		57,373		57,373
Distributions on unvested unit awards		(1,788)		(1,788)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings		9,806		9,806
Non-cash executive compensation	6	306		312
Other comprehensive loss, net of tax			(10,201)	(10,201)
Other, net		(1,467)		(1,467)
Net income	107,539	139,663		247,202
Balance, March 31, 2011	$ 181,139	$ 4,573,365	$ 15,962	$ 4,770,466

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, 2011	Three Months Ended March 31, 2010
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 290,587	$ 500,783
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash paid for acquisitions	(3,060)	(149,619)
Capital expenditures (excluding allowance for equity funds used during construction)	(210,955)	(119,721)
Contributions in aid of construction costs	2,754	2,174
Advances to affiliates, net	(11,053)	(50)
Proceeds from the sale of assets	681	1,074
Net cash used in investing activities	(221,633)	(266,142)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	917,094	77,967
Principal payments on debt	(758,615)	(241,998)
Net proceeds from issuance of Limited Partner units	57,373	504,480
Capital contribution from General Partner		8,932
Distributions to partners	(274,208)	(267,908)
Net cash (used in) provided by financing activities	(58,356)	81,473
INCREASE IN CASH AND CASH EQUIVALENTS	10,598	316,114
CASH AND CASH EQUIVALENTS, beginning of period	49,540	68,183
CASH AND CASH EQUIVALENTS, end of period	$ 60,138	$ 384,297

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

(unaudited)

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners, L.P., and its subsidiaries (Energy Transfer Partners, the Partnership, we or ETP) are managed by its general partne 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. (ETE), a publicly traded master limited partnership, 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 ETP, 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, West Virginia and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. 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 and Uinta Basins of Colorado and Utah, respectively.

Energy Transfer Interstate Holdings, LLC (ET Interstate), a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:

Transwestern Pipeline Company, LLC (Transwestern), a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern s 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.

We have the following reportable business segments: intrastate transportation and storage; interstate transportation; midstream; and retail propane and other retail propane related operations.

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Preparation of Interim Financial Statements

The accompanying condensed consolidated balance sheets as of December 31, 2010, which have been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners as of March 31, 2011 and for the three months ended March 31, 2011 and 2010, 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, and its subsidiaries as of March 31, 2011, and the Partnership s results of operations and cash flows for the three months ended March 31, 2011 and 2010. 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, 2010, as filed with the SEC on February 28, 2011.

Certain prior period amounts have been reclassified to conform to the 2011 presentation. These reclassifications had no impact on net income or total partners capital.

2. ESTIMATES:

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

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and intrastate transportation and storage operations 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 estimated operating results 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, 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, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

3. ACQUISITION:

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC (ETP-Regency LLC), a joint venture owned 70% by the Partnership and 30% by Regency Energy Partners LP (Regency), acquired all of the membership interest in LDH Energy Asset Holdings LLC (LDH), a wholly owned subsidiary of Louis Dreyfus Highbridge Energy LLC (Louis Dreyfus), from Louis Dreyfus for approximately $1.97 billion in cash. The cash purchase price paid at closing is subject to post-closing adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC upon closing to fund its 70% share of the purchase price.

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LDH owns and operates a natural gas liquids storage, fractionation and transportation business. LDH s storage assets are primarily located in Mont Belvieu, Texas, one of the largest NGL storage, distribution and trading complexes in North America. Its West Texas Pipeline transports NGLs through a 1,066-mile intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. LDH also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH is expected to significantly expand the Partnership s asset portfolio, adding an NGL platform with storage, transportation and fractionation capabilities. Additionally, this acquisition will provide additional consistent fee-based revenues.

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At the time our condensed consolidated financial statements were issued, the initial accounting for this business combination was incomplete; therefore, supplemental pro forma information was not yet available and is not included herein.

4. CASH AND CASH EQUIVALENTS:

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

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

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

	Three Months Ended March 31,	
	2011	2010
Net income	$ 247,202	$ 240,111
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	95,964	83,276
Amortization of finance costs charged to interest	2,298	2,291
Non-cash unit-based compensation expense	9,877	7,196
Non-cash executive compensation expense	312	312
Losses on disposal of assets	1,726	1,864
Distributions on unvested awards	(1,788)	(1,094)
Distributions in excess of equity in earnings of affiliates, net	4,687	10,109
Other non-cash	2,142	891
Changes in operating assets and liabilities, net of effects of acquisitions	(71,833)	155,827
Net cash provided by operating activities	$ 290,587	$ 500,783

Non-cash investing and financing activities are as follows:

	Three Months Ended March 31,	
	2011	2010
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 90,846	$ 68,436

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5. INVENTORIES:

Inventories consisted of the following:

	March 31, 2011	December 31, 2010
Natural gas and NGLs, excluding propane	$ 118,188	$ 168,378
Propane	52,653	76,341
Appliances, parts and fittings and other	125,370	117,339
Total inventories	$ 296,211	$ 362,058

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory and designate certain of these 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 cost of products sold in our condensed consolidated statements of operations.

6. INTANGIBLES AND OTHER ASSETS:

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

	March 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 250,202	$ (77,786)	$ 251,418	$ (74,910)
Noncompete agreements (3 to 15 years)	20,814	(12,180)	21,165	(11,888)
Patents (9 years)	750	(139)	750	(118)
Other (10 to 15 years)	1,320	(518)	1,320	(492)
Total amortizable intangible assets	273,086	(90,623)	274,653	(87,408)
Non-amortizable intangible assets Trademarks	77,655		77,445	
Total intangible assets	350,741	(90,623)	352,098	(87,408)
Other assets:				
Financing costs (3 to 30 years)	67,276	(34,097)	67,795	(32,528)
Regulatory assets	107,245	(15,413)	107,384	(14,445)
Other	28,203		30,400	
Total intangibles and other assets	$ 553,465	$ (140,133)	$ 557,677	$ (134,381)

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

	Three Months Ended March 31,	
	2011	2010

Reported in depreciation and amortization	$ 5,198	$ 5,146
Reported in interest expense	$ 2,298	$ 2,165

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7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations at March 31, 2011 was $7.31 billion and $6.59 billion, respectively. As of December 31, 2010, the aggregate fair value and carrying amount of our consolidated debt obligations was $7.21 billion and $6.44 billion, respectively.

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

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The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of March 31, 2011 and December 31, 2010 based on inputs used to derive their fair values:

		Fair Value Measurements at March 31, 2011 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 2,640	$ 2,640	$
Interest rate derivatives	27,580		27,580
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	65,357	65,357	
Swing Swaps IFERC	7,358	1,228	6,130
Fixed Swaps/Futures	9,284	9,284	
Options Puts	20,293		20,293
Propane Forwards/Swaps	1,395		1,395
Total commodity derivatives	103,687	75,869	27,818
Total Assets	$ 133,907	$ 78,509	$ 55,398
Liabilities:			
Interest rate derivatives	$ (24,156)	$	$ (24,156)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(55,433)	(55,433)	
Swing Swaps IFERC	(6,313)	(2,299)	(4,014)
Fixed Swaps/Futures	(18,331)	(18,331)	
Options Calls	(1,665)		(1,665)
Total commodity derivatives	(81,742)	(76,063)	(5,679)
Total Liabilities	$ (105,898)	$ (76,063)	$ (29,835)

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	Fair Value Total	Fair Value Measurements at December 31, 2010 Using Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 2,032	$ 2,032	$
Interest rate derivatives	20,790		20,790
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	15,756	15,756	
Swing Swaps IFERC	1,682	1,562	120
Fixed Swaps/Futures	42,474	42,474	
Options Puts	26,241		26,241
Options Calls	75		75
Propane Forwards/Swaps	6,864		6,864
Total commodity derivatives	93,092	59,792	33,300
Total Assets	$ 115,914	$ 61,824	$ 54,090
Liabilities:			
Interest rate derivatives	$ (18,338)	$	$ (18,338)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(17,372)	(17,372)	
Swing Swaps IFERC	(3,768)	(3,520)	(248)
Fixed Swaps/Futures	(41,825)	(41,825)	
Options Puts	(7)		(7)
Options Calls	(2,643)		(2,643)
Total commodity derivatives	(65,615)	(62,717)	(2,898)
Total Liabilities	$ (83,953)	$ (62,717)	$ (21,236)

8. 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 our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

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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, 2011	Three Months Ended March 31, 2010
Net income	$ 247,202	$ 240,111
General Partner s interest in net income	107,539	99,999
Limited Partners interest in net income	139,663	140,112
Additional earnings allocated from General Partner	348	812
Distributions on employee unit awards, net of allocation to General Partner	(1,776)	(1,157)
Net income available to Limited Partners	$ 138,235	$ 139,767
Weighted average Limited Partner units basic	193,821,128	188,424,574
Basic net income per Limited Partner unit	$ 0.71	$ 0.74
Weighted average Limited Partner units	193,821,128	188,424,574
Dilutive effect of unvested Unit Awards	705,472	702,709
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	194,526,600	189,127,283
Diluted net income per Limited Partner unit	$ 0.71	$ 0.74

9. DEBT OBLIGATIONS:

Revolving Credit Facility

We maintain a revolving credit facility (the ETP Credit Facility) that provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest, at our option, at a Eurodollar rate plus an applicable margin or a base rate. The base rate used to calculate interest on base rate loans is calculated using the greater of a prime rate or a federal funds effective rate plus 0.50%. The applicable margin for Eurodollar loans ranges from 0.30% to 0.70% based upon ETP s credit rating and is currently 0.55% (0.60% if facility usage exceeds 50%). The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership s subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

As of March 31, 2011, we had $553.5 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.42 billion taking into account letters of credit of approximately $24.9 million. The weighted average interest rate on the total amount outstanding as of March 31, 2011 was 0.81%.

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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, 2011.

10. PARTNERS CAPITAL:
Common Units Issued

The change in Common Units during the three months ended March 31, 2011 was as follows:

	Number of Units
Balance, December 31, 2010	193,212,590
Common Units issued in connection with the Equity Distribution Agreement	1,042,929
Common Units issued under equity incentive plans	12,910
Balance, March 31, 2011	194,268,429

We currently have an Equity Distribution Agreement with Credit Suisse Securities (USA) LLC (Credit Suisse) under which we may offer and sell from time to time through Credit Suisse, as our sales agent, Common Units having an aggregate offering price of up to $200.0 million. During the three months ended March 31, 2011, we received proceeds from units issued pursuant to this agreement of approximately $57.4 million, net of commissions, which proceeds were used for general partnership purposes. Approximately $116.8 million of our Common Units remain available to be issued under the agreement based on trades initiated through March 31, 2011.

On April 1, 2011, we issued 14,202,500 Common Units representing limited partner interests at $50.52 per Common Unit in a public offering. Net proceeds of approximately $695.5 million from the offering were used to repay amounts outstanding under the ETP Credit Facility, to fund capital expenditures related to pipeline construction projects and for general partnership purposes.

Quarterly Distributions of Available Cash

On February 14, 2011, we paid a cash distribution for the three months ended December 31, 2010 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on February 7, 2011.

On April 26, 2011, we declared a cash distribution for the three months ended March 31, 2011 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on May 16, 2011 to Unitholders of record at the close of business on May 6, 2011.

The total amounts of distributions declared during the three months ended March 31, 2011 and 2010 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,	
	2011	2010
Limited Partners:		
Common Units	$ 186,321	$ 170,921
Class E Units	3,121	3,121
General Partner interest	4,896	4,880
Incentive Distribution Rights	103,182	94,917

Total distributions declared	$ 297,520	$ 273,839

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Accumulated Other Comprehensive Income

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

	March 31, 2011	December 31, 2010
Net gains on commodity related hedges	$ 14,435	$ 25,245
Unrealized gains on available-for-sale securities	1,527	918
Total AOCI, net of tax	$ 15,962	$ 26,163

11. UNIT-BASED COMPENSATION PLANS:

During the three months ended March 31, 2011, employees were granted a total of 322,700 unvested awards with five-year service vesting requirements, and directors were granted a total of 2,580 unvested awards with three-year service vesting requirements. The weighted average grant-date fair value of these awards was $53.79 per unit. As of March 31, 2011 a total of 2,248,351 unit awards remain unvested, including the new awards granted during the period. We expect to recognize a total of $70.0 million in compensation expense over a weighted average period of 1.8 years related to unvested awards.

12. INCOME TAXES:

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

	Three Months Ended March 31,	
	2011	2010
Current expense:		
Federal	$ 5,028	$ 1,318
State	3,934	3,173
Total	8,962	4,491
Deferred expense:		
Federal	1,019	1,418
State	616	15
Total	1,635	1,433
Total income tax expense	$ 10,597	$ 5,924

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

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

Guarantee FEP

FEP has 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 remainder of FEP Facility obligations guaranteed by Kinder Morgan Energy Partners, L.P. (KMP). Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012, and amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate.

As of March 31, 2011, FEP had $962.5 million of outstanding borrowings issued under the FEP Facility and our contingent obligation with respect to our guaranteed portion of FEP s outstanding borrowings was $481.3 million, which was not reflected in our condensed consolidated balance sheet. The weighted average interest rate on the total amount outstanding as of March 31, 2011 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We 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 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 $5.0 million and $5.9 million for the three months ended March 31, 2011 and 2010, respectively.

Our propane operations have an agreement with Enterprise Products Partners L.P. (together with its subsidiaries Enterprise) (see Note 15) to supply a portion of our propane requirements. The agreement will continue until March 2015 and includes an option to extend the agreement for an additional year.

In connection with the sale of our investment in M-P Energy in October 2007, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

We have commitments to make capital contributions to our joint ventures and expect that capital contributions will be between $200 million and $230 million for the remainder of 2011, not including contributions to ETP-Regency LLC and our recently announced joint venture with Enterprise.

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.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were defendants in litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel storage facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation. In 2004, ETC OLP (a subsidiary of ETP) acquired the HPL Entities from AEP, at which time AEP agreed, pursuant to a Cushion Gas Litigation Agreement, 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. Following an attempted appeal of this decision by AEP, the parties to this litigation entered into a settlement agreement in February 2011 that, among other matters, recognized AEP s ownership rights to the cushion gas and recognized HPL s continued right to use this cushion gas through 2013 pursuant to a right to use agreement entered into between predecessors of AEP and HPL in 2001. The settlement agreement also reaffirms the indemnification obligations of AEP in the Cushion Gas Litigation Agreement. As a result of the settlement agreement and the indemnification provisions in the Cushion Gas Litigation Agreement, ETP does not expect that it will have any liability to either AEP or B of A with respect to the matters subject to this litigation.

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, 2011 and December 31, 2010, accruals of approximately $10.6 million and $10.2 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, 2011 condensed consolidated balance sheets or our December 31, 2010 consolidated balance sheets for our contingencies and current litigation matters other than accruals related to environmental matters and deductibles.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that can require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies there under, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage, and to limit the financial liability, which could result from such events. However, the risk of environmental or other damage is inherent in transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in 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, 2011 and December 31, 2010, accruals on an undiscounted basis of $13.0 million and $13.8 million, respectively, were recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities related to environmental matters.

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

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (PCBs). 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 2025 is $8.2 million, which is included in the aggregate environmental accruals discussed above. Transwestern received approval from the Federal Energy Regulatory Commission (the FERC) 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 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.

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

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our March 31, 2011 condensed consolidated balance sheet or our December 31, 2010 consolidated balance sheet. 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.

On August 20, 2010, the EPA published new regulations under the federal Clean Air Act (CAA) to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. On October 19, 2010, industry groups submitted a legal challenge to the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA for some monitoring aspects of the rule. The legal challenge has been held in abeyance since December 3, 2010, pending the EPA s consideration of the Petition for Administrative Reconsideration. On January 5, 2011, the EPA approved the request for reconsideration of the monitoring issues and on March 9, 2011, the EPA issued a new proposed rule and a direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If significant adverse comments are filed on the direct final rule, the EPA would address public comments in a subsequent final rule. At this point, we cannot predict when, how or if comments will be filed on the direct final rule or if a court ruling would modify the final rule, and as a result we cannot currently accurately predict the cost to comply with the rule s requirements. Compliance with the final rule is required by October 2013.

In June 2010, the EPA formally proposed modifications to existing regulations under the CAA that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The proposed rule modifications, if adopted as drafted by the EPA, may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements. The EPA expects to finalize the proposed rules in May 2011 with an effective date targeted for July 2011.

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, 2011 and 2010, $1.7 million and $1.4 million, respectively, of capital costs and $2.1 million and $1.9 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA s hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

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

14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the condensed consolidated balance sheets.

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

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

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

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.

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The following table details our outstanding commodity-related derivatives as of March 31, 2011 and December 31, 2010:

	March 31, 2011		December 31, 2010	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(28,535,000)	2011-2012	(38,897,500)	2011
Swing Swaps IFERC (MMBtu)	(50,617,500)	2011-2012	(19,720,000)	2011
Fixed Swaps/Futures (MMBtu)	(7,872,500)	2011-2012	(2,570,000)	2011
Options Calls (MMBtu)			(3,000,000)	2011
Propane:				
Forwards/Swaps (Gallons)			1,974,000	2011
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(27,200,000)	2011	(28,050,000)	2011
Fixed Swaps/Futures (MMBtu)	(30,547,500)	2011	(39,105,000)	2011
Hedged Item Inventory (MMBtu)	30,547,500	2011	39,105,000	2011
Cash Flow Hedging Derivatives				
Natural Gas:				
Fixed Swaps/Futures (MMBtu)	1,530,000	2011	(210,000)	2011
Options Puts (MMBtu)	20,970,000	2011-2012	26,760,000	2011-2012
Options Calls (MMBtu)	(20,970,000)	2011-2012	(26,760,000)	2011-2012
Propane:				
Forwards/Swaps (Gallons)	5,292,000	2011-2012	32,466,000	2011

We expect gains of $13.4 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

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

We had the following interest rate swaps outstanding as of March 31, 2011 and December 31, 2010, none of which are designated as hedges for accounting purposes:

		Notional Amount Outstanding	
Term	Type [1]	March 31, 2011	December 31, 2010
August 2012 [2]	Forward starting to pay a fixed rate of 3.64% and receive a floating rate	$ 400,000	$ 400,000
July 2018	Pay a floating rate and receive a fixed rate of 6.70%	500,000	500,000

(1) Floating rates are based on LIBOR.

(2) These forward starting swaps have an effective date of August 2012 and a term of 10 years; however, the swaps have a mandatory termination provision and will be settled in August 2012.

In addition to interest rate swaps, we also periodically enter into interest rate swaptions that enable counterparties to exercise options to enter into interest rate swaps with us. Swaptions may be utilized when our targeted benchmark interest rate for anticipated debt issuance is not attainable at that time in the interest rate swap market. Upon

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issuance of a swaption, we receive a premium which we recognize over the term of the swaption in Gains on non-hedged interest rate derivatives in our condensed consolidated statements of operations. No swaptions were outstanding as of March 31, 2011.

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 petrochemical companies and other industrials, mid-size to major oil and gas companies and power 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. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty performance.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $90.0 million and $52.2 million as of March 31, 2011 and December 31, 2010, respectively.

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

Derivative Summary

The following table provides a balance sheet overview of the Partnership s derivative assets and liabilities as of March 31, 2011 and December 31, 2010:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2011	December 31, 2010	March 31, 2011	December 31, 2010
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 17,915	$ 35,031	$ (7,785)	$ (6,631)
Commodity derivatives	1,456	6,589		
	19,371	41,620	(7,785)	(6,631)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	92,523	64,940	(82,165)	(72,729)
Commodity derivatives		275		
Interest rate derivatives	27,580	20,790	(24,156)	(18,338)
	120,103	86,005	(106,321)	(91,067)
Total derivatives	$ 139,474	$ 127,625	$ (114,106)	$ (97,698)

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.

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The following tables summarize the amounts recognized with respect to our derivative financial instruments for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion) Three Months Ended March 31, 2011	2010
Derivatives in cash flow hedging relationships:		
Commodity derivatives	$ 6,104	$ 34,108
Total	$ 6,104	$ 34,108

	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, 2011	2010
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$ 16,968	$ 5,315
Interest rate derivatives	Interest expense		71
Total		$ 16,968	$ 5,386

	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, 2011	2010
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Cost of products sold	$ 5	$ 1,121
Total		$ 5	$ 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, 2011	2010

Derivatives in fair value hedging relationships (including hedged item):			
Commodity derivatives	Cost of products sold	$ 6,417	$ (7,384)
Total		$ 6,417	$ (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, 2011	2010
Derivatives not designated as hedging instruments:			
Commodity derivatives	Cost of products sold	$ 6,379	$ 21,967
Interest rate derivatives	Gains on non-hedged interest rate derivatives	1,779	
Total		$ 8,158	$ 21,967

We recognized $17.9 million of unrealized gains and $8.8 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, 2011 and 2010, respectively. In addition, for the three months ended March 31, 2011 and 2010 we recognized unrealized losses of $8.9 million and unrealized gains of $8.1 million, respectively, on commodity derivatives and related hedged inventory accounted for as fair value hedges.

15. RELATED PARTY TRANSACTIONS:

Regency became a related party on May 26, 2010. We provide Regency with certain natural gas sales and transportation services and compression equipment and Regency provides us with certain contract compression services. For the three months ended March 31, 2011, we recorded revenue of $11.5 million, cost of products sold of $11.0 million and operating expenses of $1.5 million related to transactions with Regency.

We received $2.6 million and $0.1 million in management fees from ETE for the provision of various general and administrative services for ETE s benefit for the three months ended March 31, 2011 and 2010, respectively. The management fees for the three months ended March 31, 2011 reflect the provision of various general and administrative services for Regency. In addition, for the three months ended March 31, 2011 we recorded from Regency $2.3 million for reimbursement of various general and administrative expenses incurred by ETP.

Enterprise is considered to be a related party to us due to Enterprise s holdings of outstanding common units of ETE. We and Enterprise transport natural gas on each other s pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that expires in March 2015 and includes an option to extend the agreement for an additional year. The following table presents sales to and purchases from Enterprise:

	Three Months Ended March 31, 2011	2010
Natural Gas Operations:		
Sales	$ 135,913	$ 144,720
Purchases	8,224	6,597
Propane Operations:		
Sales	8,777	10,485
Purchases	169,966	165,764

As of December 31, 2010, Titan had forward mark-to-market derivatives for approximately 1.7 million gallons of propane at a fair value asset of $0.2 million with Enterprise. All of these forward contracts were settled as of March 31, 2011. In addition, as of March 31, 2011 and December 31, 2010, Titan had forward derivatives accounted for as cash flow hedges of 5.3 million and 32.5 million gallons of propane at fair value assets of $1.4 million and $6.6 million, respectively, with Enterprise.

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

	March 31, 2011	December 31, 2010
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$ 47,680	$ 36,736
Propane Operations	3,072	2,327
Other	27,800	14,803
Total accounts receivable from related parties	$ 78,552	$ 53,866
Accounts payable to related parties:		
Enterprise:		
Natural Gas Operations	$ 5,037	$ 2,687
Propane Operations	13,935	22,985
Other	2,107	1,505
Total accounts payable to related parties	$ 21,079	$ 27,177
Net imbalance receivable from Enterprise	$ 608	$ 1,360

16. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

	March 31, 2011	December 31, 2010
Deposits paid to vendors	$ 90,007	$ 52,192
Prepaid expenses and other	59,837	63,077
Total other current assets	$ 149,844	$ 115,269

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	March 31, 2011	December 31, 2010
Interest payable	$ 114,239	$ 135,867
Customer advances and deposits	35,521	86,191

Accrued capital expenditures	89,556	87,260
Accrued wages and benefits	32,792	61,587
Taxes payable other than income taxes	52,051	27,067
Income taxes payable	17,405	7,390
Deferred income taxes	242	365
Other	54,412	56,833
Total accrued and other current liabilities	$ 396,218	$ 462,560

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17. REPORTABLE SEGMENTS:

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

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

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

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

	Three Months Ended March 31, 2011	2010
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$ 588,678	$ 602,356
Intersegment revenues	183,081	264,136
	771,759	866,492
Interstate transportation revenues from external customers	105,101	68,269
Midstream:		
Revenues from external customers	413,195	618,707
Intersegment revenues	238,061	178,064
	651,256	796,771
Retail propane and other retail propane related revenues from external customers	557,215	561,155
All other:		
Revenues from external customers	23,388	21,494
Intersegment revenues	14,427	52,955
	37,815	74,449
Eliminations	(435,569)	(495,155)
Total revenues	$ 1,687,577	$ 1,871,981
Cost of products sold:		
Intrastate transportation and storage	$ 532,630	$ 641,506

Midstream	548,343	699,792
Retail propane and other retail propane related	315,420	309,757
All other	30,495	59,776
Eliminations	(432,431)	(485,966)
Total cost of products sold	$ 994,457	$ 1,224,865
Depreciation and amortization:		
Intrastate transportation and storage	$ 29,637	$ 28,992
Interstate transportation	19,270	12,451
Midstream	24,754	20,335
Retail propane and other retail propane related	21,020	20,088
All other	1,283	1,410
Total depreciation and amortization	$ 95,964	$ 83,276

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	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Operating income (loss):		
Intrastate transportation and storage	$ 144,074	$ 134,204
Interstate transportation	52,130	31,597
Midstream	49,504	52,332
Retail propane and other retail propane related	119,756	126,774
All other	661	7,974
Eliminations	(3,054)	(9,105)
Selling, general and administrative expenses not allocated to segments	64	562
Total operating income	$ 363,135	$ 344,338
Other items not allocated by segment:		
Interest expense, net of interest capitalized	$ (107,240)	$ (104,962)
Equity in earnings of affiliates	1,633	6,181
Losses on disposal of assets	(1,726)	(1,864)
Gains on non-hedged interest rate derivatives	1,779	
Other income, net	218	2,342
Income tax expense	(10,597)	(5,924)
	(115,933)	(104,227)
Net income	$ 247,202	$ 240,111

	As of March 31, 2011	As of December 31, 2010
Total assets:		
Intrastate transportation and storage	$ 4,711,723	$ 4,894,352
Interstate transportation	3,418,356	3,390,588
Midstream	2,143,004	1,842,370
Retail propane and other retail propane related	1,750,220	1,791,254
All other	228,143	231,428
Total	$ 12,251,446	$ 12,149,992

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 15,182	$ 25,619
Interstate transportation	37,649	35,470
Midstream	136,793	114,865
Retail propane and other retail propane related	13,402	16,298
All other	744	2,412
Total	$ 203,770	$ 194,664

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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, 2010 filed with the SEC on February 28, 2011. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A. Risk Factors included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2010.

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

Overview

The activities in which we are engaged and the wholly-owned operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following segments:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP); and
  - interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC (ET Interstate). ET Interstate is the parent company of Transwestern Pipeline Company, LLC (Transwestern), ETC Fayetteville Express Pipeline, LLC (ETC FEP) and ETC Tiger Pipeline, LLC (ETC Tiger).
- Retail propane through Heritage Operating, L.P. (HOLP) and Titan Energy Partners, L.P. (Titan).
- Other operations, including natural gas compression services through ETC Compression, LLC (ETC Compression).

Recent Developments

On May 2, 2011, ETP-Regency Midstream Holdings, LLC (ETP-Regency LLC), a joint venture owned 70% by the Partnership and 30% by Regency Energy Partners LP (Regency), acquired all of the membership interest in LDH Energy Asset Holdings LLC (LDH), a wholly owned subsidiary of Louis Dreyfus Highbridge Energy LLC (Louis Dreyfus), from Louis Dreyfus for approximately $1.97 billion in cash. The cash purchase price paid at closing is subject to post-closing adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC upon closing to fund its 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star NGL LLC (Lone Star).

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star s storage assets are primarily located in Mont Belvieu, Texas, one of the largest NGL storage, distribution and trading complexes in North America. Its West Texas Pipeline transports NGLs through a 1,066-mile intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of Lone Star is expected to significantly expand the Partnership s asset portfolio, adding an NGL platform with storage, transportation and fractionation capabilities. Additionally, this acquisition will provide additional consistent fee-based revenues.

On May 5, 2011, Lone Star announced plans to construct a 100,000 Bbls/d fractionator in Mont Belvieu, Texas. Total cost of the fractionator is expected to be approximately $375 million, of which our proportionate share would be approximately $262.5 million. The fractionator is expected to be in service by early 2013. We also announced that we are in negotiations with other pipeline operators to secure pipeline capacity that will provide NGL transportation from Jackson County, Texas to Mont Belvieu, Texas. In the event we determine that it is more prudent to build a new pipeline rather than secure pipeline capacity through another pipeline operator, we will construct a 130-mile, 20-inch NGL pipeline from the processing facility we plan to build in Jackson County to Mont Belvieu. This pipeline will provide capacity for NGL barrels from the Eagle Ford Shale or from a potential NGL pipeline from West Texas. The capacity of the proposed 20-inch pipeline is expected to be approximately 340,000 Bbls/d.

On April 26, 2011, we announced that we have agreed to form a 50/50 joint venture with Enterprise Products Partners, L.P. (together with its subsidiaries Enterprise) to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. Utilizing new and existing pipelines, the 584-mile project will originate at Enterprise s 3.1 million barrel crude oil storage facility in Cushing. We and Enterprise will each contribute existing assets to the joint venture, including our 240-mile, 24-inch diameter natural gas pipeline in East Texas, which will comprise approximately 40% of the proposed system.

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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 and propane businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets as demonstrated by our recent acquisition of LDH. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

During the past several years, we have been successful in completing several transactions that have been accretive to our Unitholders. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional cash flow to our Unitholders for years to come. In addition, we have recently announced transactions that will expand the scope of our business to include natural gas liquids storage, fractionation and transportation, and crude oil transportation.

Our principal operations include the following segments:

Intrastate transportation and storage   Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are primarily among receipt points between West Texas to East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and fuel retention. Excess fuel retained after consumption, if any, is typically sold at market prices. In addition to transport fees, we generate revenue from purchasing natural gas and transporting it across our system. The natural gas is then sold to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System purchases natural gas at the wellhead for transport and selling. Other pipelines with access to West Texas supply, such as Oasis and ET Fuel, may also purchase gas at the wellhead and other supply sources for transport across our system to be sold at market on the east side of our system. This activity allows our intrastate transportation and storage segment to capture the current basis differentials between delivery points on our system or to capture basis differentials that were previously locked in through hedges. Firm capacity long-term contracts are typically not subject to price differentials between shipping locations.

We also 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 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. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens prior to withdrawal of the gas, we will record unrealized losses or lower unrealized gains.

As noted above, any excess retained fuel is sold at market prices. To mitigate commodity price exposure, we will use financial derivatives to hedge prices on a portion of natural gas volumes retained. 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 condensed consolidated statement of operations.

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

Interstate transportation The majority of our interstate transportation revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Tiger, Fayetteville Express and Transwestern expansion shippers have made 10- to 15-year commitments to pay reservation charges for the firm capacity reserved for their use. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.

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, we retain a portion of the natural gas and NGLs processed, or a portion of the proceeds of the sales of those commodities, as a fee. When natural gas and NGL prices increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGLs decrease, so does the value of the portion we retain as a fee. For wellhead (keep-whole) contracts, we retain the difference between the price of NGLs and the cost of the gas to process the NGLs. 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 become negative; however, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs in the event it is uneconomical to process this gas. Our processing contracts and wellhead purchases in rich natural gas areas provide that we earn and take title to specified volumes of NGLs, referred to as equity NGLs. Equity NGLs can be derived from performing a service in a percent of proceeds contract or NGLs that are produced under a keep-whole arrangement. In addition to NGL price risk, our processing activity is also subject to price risk from natural gas because, in order to process the gas, in some cases we must purchase it. Therefore, lower gas prices generally result in higher processing margins.

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

Retail propane and other retail propane related operations Revenue is principally generated from the sale of propane and propane-related products and services. The retail propane segment is a margin-based business in which gross profits depend on the excess of sales price over propane supply cost. Consequently, the profitability of our retail propane business is sensitive to changes in wholesale propane prices. Our propane business is largely seasonal and dependent upon weather conditions in our service areas. We use information published by the National Oceanic and Atmospheric Administration (NOAA) to gather heating degree day data to analyze how our sales volumes may be affected by temperature. Our normal temperatures are defined as the prior ten year weighted-average temperature which is based on the average heating degree days provided by NOAA gathered from the various measuring points in our operating areas weighted by the retail volumes attributable to each measuring point.

Trends and Outlook

We are continuing our pursuit of growth through construction of new assets, expansion of our existing assets and strategic acquisitions. We expect that our results of operations in future periods will be favorably impacted upon completion of our announced growth projects and joint ventures, including the following:

The acquisition of a controlling interest in LDH on May 2, 2011 expands our asset portfolio by adding a NGL platform with storage, transportation and fractionation capabilities and also provides us with additional consistent fee-based revenues. LDH s storage assets are primarily located in Mont Belvieu, Texas, one of the largest NGL storage, distribution and trading complexes in North America. Its West

Texas Pipeline transports NGLs through a 1,066 mile intrastate pipeline system that originates in the Permian Basin in west Texas, passes through Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. LDH also owns and operates fractionation and processing assets located in Louisiana.

On May 5, 2011, Lone Star announced plans to construct a 100,000 Bbls/d fractionator in Mont Belvieu, Texas. Total cost of the fractionator is expected to be approximately $375 million, of which our proportionate share would be approximately $262.5 million. The fractionator is expected to be in service by early 2013. We also announced that we are in negotiations with other pipeline operators to secure pipeline capacity that will provide NGL transportation from Jackson County, Texas to Mont Belvieu, Texas. In the event we determine that it is more prudent to build a new pipeline rather than secure pipeline capacity through another pipeline operator, we will construct a 130-mile, 20-inch NGL pipeline from the processing facility we plan to build in Jackson County to Mont Belvieu. This pipeline will provide capacity for NGL barrels from the Eagle Ford Shale or from a potential NGL pipeline from West Texas. The capacity of the proposed 20-inch pipeline is expected to be approximately 340,000 Bbls/d.

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The Rich Eagle Ford Mainline (REM) which was announced in February 2011 and the related expansion which was announced in April 2011 will provide natural gas gathering, processing, and liquids services from the prolific Eagle Ford Shale. When fully constructed, the REM pipeline will consist of approximately 230 miles of 30-inch and 36-inch pipe with a capacity of at least 600 million cubic feet per day. We expect the initial phase of the REM to be completed in the fourth quarter of 2011 and the expansion of REM to be completed in the first quarter of 2013.

On April 26, 2011, we announced that we have agreed to form a 50/50 joint venture with Enterprise to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. Utilizing new and existing pipelines, the 584-mile project will originate at Enterprise s 3.1 million barrel crude oil storage facility in Cushing. We and Enterprise will each contribute existing assets to the joint venture, including our 240-mile, 24-inch diameter natural gas pipeline in East Texas, which will comprise approximately 40% of the proposed system. Subject to sufficient commitments from shippers and the required regulatory approvals, the new pipeline is expected to begin service in the fourth quarter of 2012.

We expect to complete the expansion of the Tiger pipeline during the second half of 2011, which will increase the total capacity of the pipeline to 2.4 Bcf/d.

Results of Operations

Consolidated Results

	Three Months Ended March 31,		
	2011	2010	Change
Revenues	$ 1,687,577	$ 1,871,981	$ (184,404)
Cost of products sold	994,457	1,224,865	(230,408)
Gross margin	693,120	647,116	46,004
Operating expenses	188,489	170,748	17,741
Depreciation and amortization	95,964	83,276	12,688
Selling, general and administrative	45,532	48,754	(3,222)
Operating income	363,135	344,338	18,797
Interest expense, net of interest capitalized	(107,240)	(104,962)	(2,278)
Equity in earnings of affiliates	1,633	6,181	(4,548)
Losses on disposal of assets	(1,726)	(1,864)	138
Gains on non-hedged interest rate derivatives	1,779		1,779
Other, net	218	2,342	(2,124)
Income tax expense	(10,597)	(5,924)	(4,673)
Net income	$ 247,202	$ 240,111	$ 7,091

See the detailed discussion of operating income by operating segment below.

Interest Expense. Interest expense increased $2.3 million for the three months ended March 31, 2011 compared to the same period last year principally due to higher borrowings on our revolving credit facility (the ETP Credit Facility) to fund growth projects. Interest expense is presented net of capitalized interest and allowance for debt funds used during construction, which totaled $1.8 million and $1.1 million for the three months ended March 31, 2011 and 2010, respectively.

Equity in Earnings of Affiliates. Equity in earnings of affiliates decreased $4.5 million for the three months ended March 31, 2011 compared to the same period last year primarily due to our transfer of substantially all of our interest in MEP to ETE on May 26, 2010. For the three months ended March 31, 2011, equity in earnings of affiliates primarily consisted of our proportionate share of the earnings of FEP.

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

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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, 2010 filed with the SEC on February 28, 2011.

Operating income (loss) by segment is as follows:

	Three Months Ended March 31,		
	2011	2010	Change
Intrastate transportation and storage	$ 144,074	$ 134,204	$ 9,870
Interstate transportation	52,130	31,597	20,533
Midstream	49,504	52,332	(2,828)
Retail propane and other retail propane related	119,756	126,774	(7,018)
All other	661	7,974	(7,313)
Eliminations	(3,054)	(9,105)	6,051
Selling, general and administrative expenses not allocated to segments	64	562	(498)
Operating income	$ 363,135	$ 344,338	$ 18,797

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

Intrastate Transportation and Storage

	Three Months Ended March 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	11,890,824	11,354,270	536,554
Revenues	$ 771,759	$ 866,492	$ (94,733)
Cost of products sold	532,630	641,506	(108,876)
Gross margin	239,129	224,986	14,143
Operating expenses	45,799	41,961	3,838
Depreciation and amortization	29,637	28,992	645
Selling, general and administrative	19,619	19,829	(210)
Segment operating income	$ 144,074	$ 134,204	$ 9,870

Volumes. We experienced an increase in volumes transported on our intrastate transportation systems under long-term contracts primarily due to increased production by our customers in areas where our assets are located. The increase in volumes transported under long-term contracts was offset by a decrease in interruptible volumes due to less favorable natural gas price environment and lower basis differentials between the West and East Texas market hubs.

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Change
Transportation fees	$ 142,666	$ 140,798	$ 1,868
Natural gas sales and other	45,199	40,010	5,189
Retained fuel revenues	34,982	35,702	(720)
Storage margin, including fees	16,282	8,476	7,806
Total gross margin	$ 239,129	$ 224,986	$ 14,143

For the three months ended March 31, 2011, intrastate transportation and storage gross margin increased compared to the same period in the prior year primarily due to the following factors:

The increase in transportation fees of $1.9 million for the three months ended March 31, 2011 as compared to the same period last year was mainly due to the volume increases discussed above. For the three months ended March 31, 2011 and 2010, transportation fees included intercompany transactions with our marketing affiliate of $8.9 million and $10.9 million, respectively, which are reflected as cost of products sold in our midstream segment.

Margin from the sales of natural gas and other activities increased $5.2 million during the three months ended March 31, 2011 as compared to the three months ended March 31, 2010, primarily due to more favorable impacts from system optimization activities. The margin from the sales of natural gas and other includes natural gas purchased for transport and sale, and gains and losses on derivatives used to hedge transportation activities and net retained fuel. The margin from natural gas sales and other includes unrealized gains on derivatives of $16.3 million and $4.9 million in the three months ended March 31, 2011 and 2010, respectively.

Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Despite higher retention volumes for the three months ended March 31, 2011 as compared to the three months ended March 31, 2010, retention revenue decreased $0.7 million due to less favorable pricing. Our average retention price for physical gas we retained as revenue during the three months ended March 31, 2011 was $4.16/MMBtu compared to $4.42/MMBtu for the three months ended March 31, 2010.

Storage margin was comprised of the following:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Change
Withdrawals from storage natural gas inventory (MMBtu)	15,124,753	27,016,787	(11,892,034)
Margin on physical sales	$ 10,512	$ 64,378	$ (53,866)
Fair value adjustments	1,522	(68,555)	70,077
Settlements of derivatives	5,770	(10,499)	16,269
Unrealized (losses) gains on derivatives	(10,957)	13,118	(24,075)
Net impact of natural gas inventory transactions	6,847	(1,558)	8,405
Revenues from fee-based storage	9,601	11,299	(1,698)
Other costs	(166)	(1,265)	1,099

Total storage margin	$ 16,282	$ 8,476	$ 7,806

In addition to fee based contracts, our storage margin is also impacted by the price variance between the carrying amount of our inventory and the locked-in sales price of our financial derivatives. We apply fair value hedge accounting to the natural gas we purchase for storage and adjust the carrying amount of our inventory to the spot price at the end of each period. These inventory fair value adjustments are offset by a portion of the unrealized gains or losses on the related financial derivative. These changes in value occur until the settlement of the derivative or the actual withdrawal of the inventory, when the earnings are realized. The unrealized gains and losses that we recognize represent the change in the spread between the spot price and the forward price. This spread can widen or narrow, thereby creating unrealized losses or gains, until ultimately converging when the financial contract settles.

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The increase in our storage margin of $7.8 million for the three months ended March 31, 2011 as compared to the three months ended March 31, 2010 was primarily driven by carrying a larger volume of inventory out of the withdrawal season that was subject to mark-to-market impact of the spread between spot price and the forward prices narrowing during the period. We withdrew principally all of our natural gas inventory from storage during the same period last year.

Operating Expenses. For the three months ended March 31, 2011, intrastate transportation and storage operating expenses increased principally due to an increase in natural gas consumed for compression of $2.2 million, an increase in maintenance and operating expenses of $1.0 million and an increase in employee-related costs of $0.9 million.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased during the three months ended March 31, 2011 compared to the prior periods primarily due to the completion of pipeline projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative. Intrastate transportation and storage selling, general and administrative expenses decreased for the three months ended March 31, 2011 as a result of a decrease in employee-related costs (including allocated overhead expenses) of $0.3 million.

Interstate Transportation

	Three Months Ended March 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	2,250,166	1,557,921	692,245
Natural gas sold (MMBtu/d)	23,586	20,043	3,543
Revenues	$ 105,101	$ 68,269	$ 36,832
Operating expenses	26,744	16,061	10,683
Depreciation and amortization	19,270	12,451	6,819
Selling, general and administrative	6,957	8,160	(1,203)
Segment operating income	$ 52,130	$ 31,597	$ 20,533

The interstate transportation segment data presented above does not include our interstate pipeline joint ventures, for which we reflect our proportionate share of income within Equity in earnings of affiliates below operating income in our condensed consolidated statement of operations. We recorded equity in earnings related to FEP of $0.8 million for the three months ended March 31, 2011 and $5.5 million related to MEP for the three months ended March 31, 2010. As discussed above, we transferred substantially all of our interest in MEP to ETE on May 26, 2010.

Volumes. Transported volumes increased during the three months ended March 31, 2011 due to transported volumes of 835,849 MMBtu/d on the Tiger pipeline, which was placed in service in December 2010. The incremental volumes related to the Tiger pipeline were offset by lower volumes on the Transwestern pipeline during the three months ended March 31, 2011 compared to the same period in the prior year.

Revenues. For the three months ended March 31, 2011, interstate transportation revenues increased compared to the three months ended March 31, 2010 primarily as a result of $39.5 million related to the Tiger pipeline, which was placed in service in December 2010. This increase was slightly offset by decreased revenue from the Transwestern pipeline as a result of lower volumes.

Operating Expenses. Interstate transportation operating expenses increased during the three months ended March 31, 2011 primarily due to an increase of $7.0 million in ad valorem taxes resulting from the Tiger pipeline which was placed in service in December 2010, and an increase of $2.9 million in employee-related costs.

Depreciation and Amortization. Depreciation and amortization expense increased during the three months ended March 31, 2011, primarily due to incremental depreciation associated with the Tiger pipeline which was placed in service in December 2010.

Selling, General and Administrative. Selling, general and administrative expenses decreased during the three months ended March 31, 2011 primarily due to lower employee-related costs and allocated overhead.

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Midstream

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Change
NGLs produced (Bbls/d)	49,752	48,312	1,440
Equity NGLs produced (Bbls/d)	15,894	17,696	(1,802)
Revenues	$ 651,256	$ 796,771	$ (145,515)
Cost of products sold	548,343	699,792	(151,449)
Gross margin	102,913	96,979	5,934
Operating expenses	24,407	17,830	6,577
Depreciation and amortization	24,754	20,335	4,419
Selling, general and administrative	4,248	6,482	(2,234)
Segment operating income	$ 49,504	$ 52,332	$ (2,828)

Volumes. NGL production increased during the three months ended March 31, 2011 primarily due to increased inlet volumes at our Godley plant as a result of more production by our customers in the North Texas area in addition to favorable processing conditions. The decrease in equity NGL production is primarily due to a higher concentration of volumes under fee-based contracts during the three months ended March 31, 2011 as compared to the same period last year.

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Change
Gathering and processing fee-based revenues	$ 59,607	$ 54,294	$ 5,313
Non fee-based contracts and processing	46,370	47,271	(901)
Other	(3,064)	(4,586)	1,522
Total gross margin	$ 102,913	$ 96,979	$ 5,934

For the three months ended March 31, 2011, midstream gross margin increased compared to the same period last year due to the following:

Increased volumes in our North Texas system resulted in increased fee-based revenues of $2.5 million for the three months ended March 31, 2011 as compared with the same period last year. Additionally, increased volumes resulting from our recent acquisitions and other growth capital expenditures located in Louisiana provided an increase in our fee-based margin of $2.3 million for the three months ended March 31, 2011 as compared with the same period last year. Fee-based revenues on our Colorado system also increased slightly for the three months ended March 31, 2011 as compared to the three months ended March 31, 2010.

Our non fee-based gross margins decreased $0.9 million primarily due to lower equity NGL production volumes as discussed above. Favorable NGL prices partially offset the decrease in equity gallon production. The composite NGL price increased for the three months ended March 31, 2011 to $1.20 per gallon from $1.11 per gallon during the three months ended March 31, 2010.

The increase in other midstream gross margin was related to margin associated with processing where third party processing capacity is utilized. This activity was offset by losses of $1.7 million from marketing activities due to less favorable market conditions compared to the three months ended March 31, 2010. Other midstream gross margin included unrealized gains on derivatives of $0.5 million during the three months ended March 31, 2011 compared to unrealized losses of $2.9 million during the three months ended March 31, 2010.

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Operating Expenses. Operating expenses increased between the periods primarily as a result of an increase of $2.4 million in maintenance and operating costs, an increase of $1.9 million in property taxes, an increase of $0.7 million in professional fees and an increase of $1.6 million in employee related costs.

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

Selling, General and Administrative. Midstream selling, general and administrative expenses decreased for the three months ended March 31, 2011 primarily as a result of a decrease in employee-related costs (including allocated overhead expenses) of $2.5 million.

Retail Propane and Other Retail Propane Related

	Three Months Ended March 31, 2011	2010	Change
Retail propane gallons (in thousands)	204,140	217,611	(13,471)
Retail propane revenues	$ 528,466	$ 533,439	$ (4,973)
Other retail propane related revenues	28,749	27,716	1,033
Retail propane cost of products sold	310,864	304,981	5,883
Other retail propane related cost of products sold	4,556	4,776	(220)
Gross margin	241,795	251,398	(9,603)
Operating expenses	88,185	91,732	(3,547)
Depreciation and amortization	21,020	20,088	932
Selling, general and administrative	12,834	12,804	30
Segment operating income	$ 119,756	$ 126,774	$ (7,018)

Volumes. For the three months ended March 31, 2011, volumes were 13.5 million gallons below the same period last year. The combined average temperatures in our operating areas were approximately 2.7% colder than normal as compared to weather which was approximately 5.3% colder than normal during the same period in 2010. The combination of weather patterns along with continued customer conservation negatively impacted our sales volumes for the three months ended March 31, 2011.

Gross Margin. Gross margin decreased $14.3 million during the three months ended March 31, 2011 compared to the same period last year due to the volume decrease discussed above. The impact of the lower volumes was partially offset by a $3.1 million favorable impact attributable to mark-to-market adjustments for our financial instruments used in our commodity price risk management activities and a $1.3 million increase in other retail propane related gross profit.

Operating Expenses. Operating expenses were lower for the three months ended March 31, 2011 compared to the same period last year primarily due to decreases of $4.0 million in performance-based bonus accruals and $1.5 million in other general operating expenses. These decreases were partially offset by an increase of $1.2 million in our vehicle fuel expenses due to the increase in fuel costs between periods.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense during the three months ended March 31, 2011 compared to the same period last year was primarily due to increased depreciation expense related to assets placed in service and acquisitions.

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 $600 million and $650 million in for the remainder of 2011;

- 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 $160 million and $190 million for the remainder of 2011;

- growth capital expenditures for our retail propane segment of between $15 million and $25 million for the remainder of 2011; and

- maintenance capital expenditures of between $90 million and $100 million for the remainder of 2011, 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 to make capital contributions to our joint ventures of between $250 million and $300 million for the remainder of 2011, including $50 million to $75 million of contributions to ETP-Regency LLC (renamed Lone Star as discussed above in Recent Developments). This total does not include any contributions we may make related to our recently announced joint venture with Enterprise.

In addition, we may enter into acquisitions, including the potential acquisition of new pipeline systems and propane operations. We closed the LDH acquisition on May 2, 2011. Our 70% share of the purchase price was $1.38 billion, which was partially funded with borrowings under the ETP Credit Facility.

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 $57.4 million in net proceeds during the three months ended March 31, 2011 under our equity distribution program, as described in Note 10 to our condensed consolidated financial statements. As of March 31, 2011, in addition to approximately $60.1 million of cash on hand, we had available capacity under the ETP Credit Facility of approximately $1.42 billion. Based on our current estimates, we expect to utilize our revolver capacity, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2011; 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.

On April 1, 2011, we issued 14,202,500 Common Units representing limited partner interests at $50.52 per Common Unit in a public offering. Net proceeds of approximately $695.5 million from the offering were used to repay amounts outstanding under the ETP Credit Facility, to fund capital expenditures related to pipeline construction projects and for general partnership purposes.

In April 2011, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the DRIP). The DRIP provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. Currently, the registration statement covers the issuance of up to 5,750,000 common units under the DRIP.

Cash Flows

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

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Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in Results of Operations above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense 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 a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Three months ended March 31, 2011 compared to three months ended March 31, 2010. Cash provided by operating activities during 2011 was $290.6 million as compared to $500.8 million for 2010 and net income was $247.2 million and $240.1 million for 2011 and 2010, respectively. The difference between net income and cash provided by operating activities for the three months ended March 31, 2011 and 2010 primarily consisted of non-cash items totaling $112.3 million and $95.8 million, respectively, and changes in operating assets and liabilities of $71.8 million and $155.8 million, respectively.

The non-cash activity in 2011 and 2010 consisted primarily of depreciation and amortization of $96.0 million and $83.3 million, respectively. In addition, non-cash compensation expense was $10.2 million and $7.5 million for 2011 and 2010, respectively.

Cash paid for interest, net of interest capitalized, was $129.0 million and $129.2 million for the three months ended March 31, 2011 and 2010, 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, 2011 compared to three months ended March 31, 2010. Cash used in investing activities during 2011 was $221.6 million as compared to $266.1 million for 2010. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2011 were $211.0 million, including changes in accruals of $5.6 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2010 of $119.7 million, including changes in accruals of $22.2 million. In addition, in 2011 we paid cash for acquisitions of $3.1 million and made advances to our joint ventures of $11.1 million. We paid cash for acquisitions of $149.6 million during 2010.

Growth capital expenditures for 2011, before changes in accruals, were $140.5 million for our midstream and intrastate transportation and storage segments, $38.4 million for our interstate transportation segment, and $7.0 million for our retail propane and all other segments. We also incurred $19.6 million in maintenance capital expenditures, of which $12.8 million related to our midstream and intrastate transportation and storage segments, $1.8 million related to our interstate transportation segment and $5.1 million related to our retail propane and all other segments.

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 and all other segments. We also incurred $19.6 million in 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 transportation segment and $8.3 million related to our retail propane and all other segments.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.

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Three months ended March 31, 2011 compared to three months ended March 31, 2010. Cash used in financing activities during 2011 was $58.4 million as compared to cash provided by financing $81.5 million for 2010. In 2011, we received $57.4 million in net proceeds from Common Unit offerings under our equity distribution program, as compared to net proceeds from Common Unit offerings of $504.5 million in 2010 (see Note 10 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 2011, we had a net increase in our debt level of $158.5 million as compared to a net decrease of $164.0 million for 2010. In addition, we paid distributions of $274.2 million to our partners in 2011 as compared to $267.9 million in 2010.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2011	December 31, 2010
ETP Senior Notes	$ 5,050,000	$ 5,050,000
Transwestern Senior Unsecured Notes	870,000	870,000
HOLP Senior Secured Notes	103,127	103,127
Revolving credit facilities	553,524	402,327
Other long-term debt	8,719	9,541
Unamortized discounts	(11,876)	(12,074)
Fair value adjustments related to interest rate swaps	15,857	17,260
Total debt	$ 6,589,351	$ 6,440,181

The terms of our consolidated indebtedness are described in more detail in our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011.

The $5.05 billion of aggregate principal amount of ETP Senior Notes includes $600 million of principal amount of 9.7% Senior Notes due March 15, 2019. The holders of those notes will have the right to require us to repurchase all or a portion of the notes on March 15, 2012 at a purchase price of equal to 100% of the principal amount (par value) of the notes tendered. The current market value of the notes is significantly in excess of the principal amount, making a repurchase at par value uneconomic by the holder. However, if such a repurchase were to occur, we would intend to refinance any amounts paid on a long-term basis.

Revolving Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest, at our option, at a Eurodollar rate plus an applicable margin or a base rate. The base rate used to calculate interest on base rate loans will be calculated using the greater of a prime rate or a federal funds effective rate plus 0.50%. The applicable margin for Eurodollar loans ranges from 0.30% to 0.70% based upon ETP s credit rating and is currently 0.55% (0.60% if facility usage exceeds 50%). The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of March 31, 2011, we had a balance of $553.5 million outstanding under the under the ETP Credit Facility. Taking into account letters of credit of approximately $24.9 million, the amount available under the credit facility was $1.42 billion. The weighted average interest rate on the total amount outstanding at March 31, 2011 was 0.81%. In April 2011, we repaid the outstanding borrowings under the ETP Credit Facility with proceeds from our Common Unit Offering. On May 2, 2011, we borrowed $1.26 billion under the ETP Credit Facility to fund a portion of our proportionate share of the purchase price paid by ETP-Regency LLC to acquire all of the membership interest in LDH from Louis Dreyfus.

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 remainder of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate.

As of March 31, 2011, FEP had $962.5 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our guaranteed portion of FEP s outstanding borrowings was $481.3 million, which is not reflected on our condensed consolidated balance sheets as of March 31, 2011. The weighted average interest rate on the total amount outstanding as of March 31, 2011 was 3.2%.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at March 31, 2011.

Cash Distributions

Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash, as defined, 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.

On February 14, 2011, we paid a cash distribution for the three months ended December 31, 2010 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on February 7, 2011.

On April 26, 2011, we announced the declaration of a cash distribution for the three months ended March 31, 2011 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on May 16, 2011 to Unitholders of record at the close of business on May 6, 2011.

The total amounts of distributions declared during the three months ended March 31, 2011 and 2010 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,	
	2011	2010
Limited Partners:		
Common Units	$ 186,321	$ 170,921
Class E Units	3,121	3,121
General Partner interest	4,896	4,880
Incentive Distribution Rights	103,182	94,917
Total distributions declared	$ 297,520	$ 273,839

Critical Accounting Policies

Disclosure of our critical accounting policies is included in our Annual Report on Form 10-K for the year ended December 31, 2010.

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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, 2010, in addition to the interim unaudited condensed consolidated financial statements, accompanying notes and management s discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2010. Since December 31, 2010, there have been no material changes to our primary market risk exposures or how those exposures are managed.

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

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Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of March 31, 2011 and December 31, 2010, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas and gallons for propane. Dollar amounts are presented in thousands.

	March 31, 2011			December 31, 2010		
	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	(28,535,000)	$ 10,255	$ 2,475	(38,897,500)	$ (2,334)	$ 304
Swing Swaps IFERC	(50,617,500)	1,045	6,438	(19,720,000)	(2,086)	2,228
Fixed Swaps/Futures	(7,872,500)	(7,851)	3,435	(2,570,000)	(11,488)	1,176
Options Calls				(3,000,000)	62	7
Propane:						
Forwards/Swaps				1,974,000	275	258
Fair Value Hedging Derivatives						
Natural Gas:						
Basis Swaps						
IFERC/NYMEX	(27,200,000)	(331)	111	(28,050,000)	722	322
Fixed Swaps/Futures	(30,547,500)	(2,691)	13,575	(39,105,000)	8,599	16,837
Cash Flow Hedging Derivatives						
Natural Gas:						
Fixed Swaps/Futures	1,530,000	62	673	(210,000)	232	93
Options Puts	20,970,000	8,006	5,665	26,760,000	10,545	7,125
Options Calls	(20,970,000)	3,843	1,057	(26,760,000)	4,812	1,565
Propane:						
Forwards/Swaps	5,292,000	1,395	727	32,466,000	6,589	4,196

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

Interest Rate Risk

As of March 31, 2011, we had $553.5 million of variable rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $5.5 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements. To the extent that we have debt with variable interest rates that is not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates. We had the following interest rate swaps outstanding as of March 31, 2011 and December 31, 2010 (dollars in thousands), none of which are designated as hedges for accounting purposes:

Term	Type	Notional Amount Outstanding March 31, 2011	Notional Amount Outstanding December 31, 2010
August 2012 (1)	Forward starting to pay a fixed rate of 3.64% and receive a floating rate	$400,000	$400,000
July 2018	Pay a floating rate and receive a fixed rate of 6.70%	500,000	500,000

(1) These forward starting swaps have an effective date of August 2012 and a term of 10 years; however, the swaps have a mandatory termination provision and will be settled in August 2012.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings of approximately $0.1 million as of March 31, 2011 and $0.3 million as of December 31, 2010. For the $500.0 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $5.0 million. For the $400.0 million of forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until August 2012 when the swaps are settled.

We periodically enter into interest rate swaptions when our targeted benchmark interest rates for anticipated debt issuances are not attainable at the time in the interest rate swap market. Swaptions enable counterparties to exercise options to enter into interest rate swaps with us in exchange for premiums. As of March 31, 2011, we had no swaptions outstanding.

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 petrochemical companies and other industrials, mid-size to major oil and gas companies and power 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. Currently, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

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

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Under the supervision and with the participation of senior management, including the Chief Executive Officer (Principal Executive Officer) and the Chief Financial Officer (Principal Financial Officer) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a 15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of March 31, 2011 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

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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, 2011 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, 2010 and Note 13 Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

ITEM 1A. RISK FACTORS

Our recently announced transactions present several risks. Many of those risks are similar to the risks associated with our existing businesses, as we have previously disclosed. However, certain of those risks represent new risks related to our business or existing risks that have become more significant. The following risk factors should be read in conjunction with our risk factors described in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010.

Risks Related to Our Business

We do not control, and therefore may not be able to cause or prevent certain actions by, certain of our joint ventures.

Certain of our joint ventures have their own governing boards, and we may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in our or the joint venture s best interests. Likewise, we may be unable to prevent actions of the joint venture.

The profitability of certain activities in our NGL and refined products storage business, our NGL transportation business and our off-gas processing and fractionating business are largely dependent upon market demand for NGLs and refined products, which has been volatile, and competition in the market place, both of which are factors that are beyond our control.

Our NGL and refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers. However, a portion of our revenue is derived from fungible storage and throughput arrangements, under which our revenue is more dependent upon demand for storage from our customers. Demand for these services may fluctuate as a result of changes in commodity prices. Our NGL and refined products storage assets are primarily located in the Mont Belvieu area, which is a significant storage distribution and trading complex with multiple industry participants, any one of which could compete for the business of our existing and potential customers. Any loss of business from existing customers or our inability to attract new customers could have an adverse effect on our results of operations.

Revenue from our NGL transportation systems is exposed to risks due to fluctuations in demand for transportation as a result of unfavorable commodity prices and competition from nearby pipelines. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. We may not be able to renew these contracts or execute new customer contracts on favorable terms if NGL prices decline and demand for our transportation services decreases. Any loss of existing customers due to decreased demand for our services or competition from other transportation service providers could have a negative impact on our revenues and have an adverse effect on our results of operations.

Revenue from our off-gas processing and fractionating system in south Louisiana is exposed to risks due to the low concentration of suppliers near our facilities and the possibility that connected refineries may not provide us with sufficient off-gas for processing at our facilities. The connected refineries may also experience outages due to maintenance issues and severe weather, such as hurricanes. We receive revenues primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions, and other factors, including:

- the impact of weather on the demand for oil, natural gas and NGLs;

- the level of domestic oil and natural gas production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Certain of our assets may become subject to regulation.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. The 1,066-mile West Texas Pipeline, which we acquired as part the LDH acquisition, transports NGLs within the state of Texas and is subject to regulation by the Texas Railroad Commission (TRRC). This NGL transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Such services must be provided in a manner that is just, reasonable and non-discriminatory. We believe that this NGL system does not provide interstate service and that it is thus not subject to FERC jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. We cannot guarantee that the jurisdictional status of this NGL pipeline system will remain unchanged, however, should it be found jurisdictional, the FERC s rate-making methodologies may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

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, 2011.

Period	Total Number of Units Purchased (1)	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Yet Be Purchased Under

			or Programs	the Plans or Programs
January 1 January 31	246	$ 50.28	N/A	N/A
February 1 February 28			N/A	N/A
March 1 March 31	1,422	54.02	N/A	N/A
Total	1,668	$ 53.47	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, 2011, certain of the participants in the 2004 Unit Plan and the 2008 Long-Term Incentive Plan elected to have a portion of the Common Units to which they were entitled upon vesting of restricted units withheld by the Partnership to satisfy the Partnership s tax withholding obligations. None of the Common Units delivered to recipients of unit awards upon vesting were purchased by the Partnership through a publicly announced open-market plan or program.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

(a) Exhibits

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

	Exhibit Number	Description
(8)	2.1	Redemption and Exchange Agreement, dated May 10, 2010, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(11)	2.2	Purchase Agreement, dated March 22, 2011, among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC and Louis Dreyfus Highbridge Energy LLC, Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(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.
(10)	3.6	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C.
(9)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
(9)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
(9)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
(*)	10.1	Seventh Amendment Agreement dated as of February 22, 2011, to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)	10.2	Guarantee, dated as of March 22, 2011, by Energy Transfer Partners, L.P. in favor of Louis Dreyfus Highbridge Energy LLC.
(13)	10.3	Assumption, Contribution and Indemnification Agreement, dated as of March 22, 2011, by and between Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Condensed Consolidated Balance Sheets as of March 31, 2011 and December 31, 2010; (ii) our Condensed Consolidated

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Exhibit Number	Description
	Statements of Operations for the three months ended March 31, 2011 and 2010; (iii) our Condensed Consolidated Statements of Comprehensive Income for the three months ended March 31, 2011 and 2010; (iv) our Condensed Consolidated Statement of Partners Capital for the three months ended March 31, 2011; (v) our Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2011 and 2010; and (vi) the notes to our Condensed Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.

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

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

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

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

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

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

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

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

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

(10) Incorporated by reference to Exhibit 3.1 to the Registrant s Form 8-K filed August 10, 2010.

(11) Incorporated by reference to Exhibit 2.1 to Registrant s Form 8-K/A filed on March 25, 2011.

(12) Incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K/A filed on March 25, 2011.

(13) Incorporated by reference to Exhibit 10.2 to Registrant s Form 8-K/A filed on March 25, 2011.

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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 6, 2011

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